ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

Informational Letter
IL 81-1

CANADIANA
JAN 21 1981

TO: All Operators
(Oil and Gas, Pipeline, Rural Gas, Hydro and Electric)

The Board wishes to announce an extension of the Whitecourt Area Office boundaries as outlined on the attached map. These changes are being made in conjunction with the opening of a Grande Prairie Satellite Office. All routine correspondence and telephone calls pertaining to wells and facilities in the expanded area should still be directed to the Whitecourt Area Office as is done at present.

The Grande Prairie Satellite Office will be under the direction of Mr. R. B. Doherty, Area Supervisor, Whitecourt Area Office. The staff at Grande Prairie will initially consist of two men, Mr. Terry Jordan, Senior Inspector, and Mr. Dick Spencer, Area Inspector. For information or assistance with specific Grande Prairie problems or other non-routine matters Messrs Jordan or Spencer may be reached at:

9930 Prairie Road
Grande Prairie, Alberta
T8V 3S1
Telephone: 539-2138

For service after hours, weekends and
holidays: Whitecourt - 778-3812

DATED at Calgary, Alberta on 7 January 1981.

R.W. Edgecombe

R. W. Edgecombe
Assistant Manager
Field Operations
Development Department

ENERGY RESOURCES CONSERVATION BOARD
DEVELOPMENT AND ENVIRONMENT PROTECTION DEPARTMENTS

CALGARY OFFICE		Telephone Number
	640-5th Avenue S.W. Calgary, Alberta, T2P 3G4 Telex 03-82-17-17	261-8311 261-9917 (AH+HO)

Manager, Development Department	L.A.(Lloyd) Bellows	261-8169
Manager, Environment Protection Department	E. R.(Ed) Brushett	261-8121
Assistant Manager, Drilling & Production	Wm.H.(Bill) Wolff	261-8172
Assistant Manager, Field Operations	R.W.(Rod) Edgecombe	261-8174
Senior Drilling & Production Engineer	L.E.(Lloyd) Hicklin	261-8176
Senior Drilling & Production Engineer	J.R.(John) Nichol	261-8283
Senior Environmental Engineer	W. G. (Bill) Remmer	261-8313
Senior Environmental Co-ordinator	H. F. (Harald) Thimm	261-8321
Senior Staff Supervisor, Field Operations	B.E.(Brian) McFarlane	261-8167
Supervisor of Well Licensing	D.L.(Don) Skappak	261-8159
Supervisor, Drilling Section	W.(Bill) Wylie	261-8102

DEVELOPMENT DEPARTMENT - AREA OFFICES

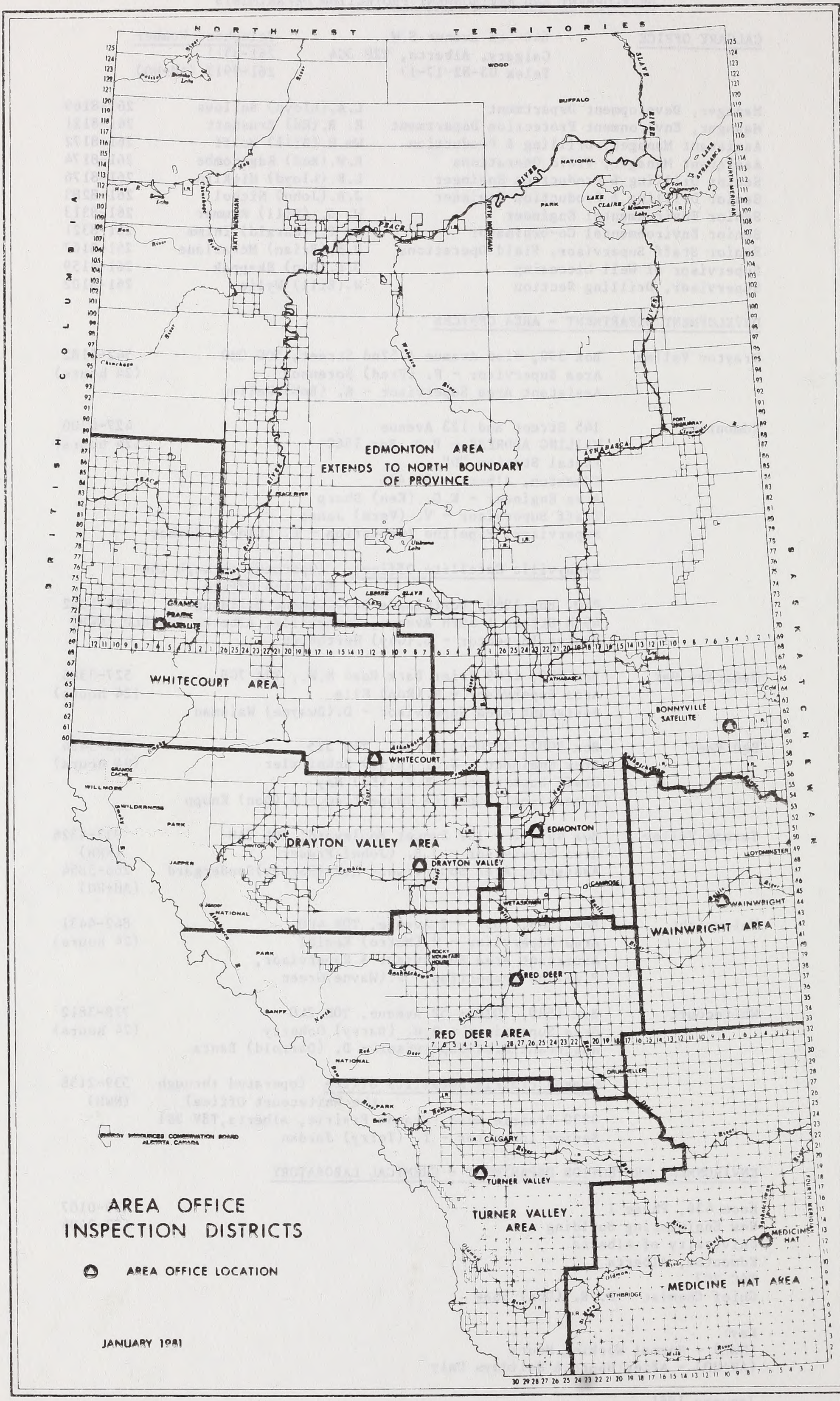
Drayton Valley	Box 390, 51st Avenue & 52nd Street, TOE 0M0 Area Supervisor - F. (Fred) Sorenson Assistant Area Supervisor - R. (Bob) Keller	542-5182 (24 hours)
Edmonton	145 Street and 123 Avenue MAILING ADDRESS - P.O. Box 3560 Postal Station "D" Edmonton, Alberta T5L 4J6 Area Engineer - K.G. (Ken) Sharp Staff Supervisor - V. (Vern) Jones Supervisor, Pipeline Inspection - L. (Lloyd) Bowhay	427-0200 (24 hours)
	Bonnyville Satellite Office: (Operated through the Edmonton Office) P.O. Box 1969, Northlands Development Building 49th Street & 50th Avenue, Bonnyville, Alberta, T0A 0L0 Senior Inspector - G.(Guy) Hurtubise	826-5352 (NWH)
Medicine Hat	Box 909, 1609 Brier Park Road N.W., T1A 7G8 Area Supervisor - R.(Ron) Elle Assistant Area Supervisor - D.(Dwayne) Waisman	527-3385 (24 hours)
Red Deer	Box 5002, 4920-51 Street, T4N 5Y5 Area Engineer - W.J. (Bill) Schnitzler Staff Supervisor - E.F. (Ed) May Supervisor, Pipeline Inspection - D.(Don) Knopp	343-5454 (24 hours)
Turner Valley	Box 447, 2 - 102 Sunset Boulevard, T0L 2A0 Area Supervisor - J.S. (John) Fraser Assistant Area Supervisor- H.E.(Harvey)Sondergard	933-4326 (NWH) 266-5854 (AH+HO)
Wainwright	Box 1506, 1037 - 2 Avenue, T0B 4P0 Area Supervisor - M.(Metro) Koziol Assistant Area Supervisor & Supervisor, Pipeline Inspection - W.(Wayne)Green	842-4431 (24 hours)
Whitecourt	Box 1530, 5020 - 52 Avenue, T0E 2L0 Area Supervisor - R.B. (Barry) Doherty Assistant Area Supervisor - D. (Darrold) Banta	778-3812 (24 hours)
	Grande Prairie Satellite Office (operated through the Whitecourt Office) 9930 Prairie Road, Grande Prairie, Alberta, T8V 3S1 Senior Inspector - T. (Terry) Jordan	539-2138 (NWH)

ENVIRONMENT PROTECTION DEPARTMENT - CHEMICAL LABORATORY

Room 436, Phase I New Engineering Building University of Alberta Edmonton, Alberta T6C 2G7 Chief Chemist - D. R. (Don) Shaw	439-0107 433-3494

Key:
(NWH) - Normal Working Hours
(AH+HO) - After Hours & Holidays Only

January 1981



AREA OFFICE INSPECTION DISTRICTS

△ AREA OFFICE LOCATION

JANUARY 1981

C2

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

Informational Letter
IL 81-2

TO: All Oil and Gas Operators

GAS WELL TESTING REGULATORY AND ADMINISTRATION AMENDMENTS

The Board has amended certain sections of the Oil and Gas Conservation Regulations regarding the testing of gas wells and the reporting of test results to the Board. The intent of the amendments is to provide industry with clearer direction concerning testing and reporting requirements and to introduce certain new requirements. The amendments are also intended to simplify the Board's gas well testing requirements and improve the quality of deliverability and pressure data obtained for all producing pools. The purpose of this informational letter is to outline and discuss the reasons for some of the more important changes made. A copy of sections 11.103, 11.120(1)(c)), 11.130, and 11.135 as amended are attached as Appendix 1.

It should be noted that the provisions for relief from testing requirements, where warranted, are continued (sections 11.103(5) and 11.130(12)).

PRESSURE TESTING

A new section, 11.103, requires a licensee of a gas well completed in a designated pool to obtain satisfactory subsurface pressure measurements using a properly calibrated subsurface gauge before any production is obtained. In addition, the licensee of a gas well completed in a designated pool from which production is regularly being taken will be required to determine the stabilized shut-in reservoir pressure in the well every two years.

WELL FLOW TESTING

With respect to deliverability testing of gas wells, section 11.130 subsection (10) has been amended to require the licensee or test coordinator of any producing gas well to submit a testing schedule which provides for the determination of the absolute open flow potential every four years throughout the producing life of the well. The testing frequency was previously every three years. This change will permit better coordination of deliverability tests with the biennial bottom hole pressure surveys. Also, it should be noted that these testing requirements apply to all gas wells except those in pools which were previously granted relief from testing requirements and in shallow gas pools where the testing requirements were modified as outlined in Informational Letter IL-OG 75-9.

GAS WELL FLARING

Section 11.135 previously provided for limited flaring of gas, without Board authorization, in the clean-up and testing of wells in undesignated pools. This has now been extended to pools designated by Board order.

ADMINISTRATION

The Board intends to implement a procedure whereby a schedule would be instituted for the obtaining of deliverability tests and subsurface pressure tests for all wells in the province. A systematic approach to the obtaining and reporting of tests will aid the Board in the processing of results and in the long term provide industry with more reliable data. The Board will issue an annual letter to all operators listing the gas pools which should be tested, the operator of single well pools, or coordinating operator of multi-well pools, and a proposed test date for each pool. This letter will be similar to and complement the Board's Oil Department annual letter entitled, "Provincial Program of Subsurface Pressure Surveys of Crude Oil Pools".

The Board in Informational Letter IL 71-23 outlined a system whereby the operator, normally the operator of the largest number of wells in a pool, was asked to act as the coordinating operator of that pool. The Board remains convinced that the quality of data can be improved and the cost of obtaining adequate data reduced through the increased liaison among operators of each pool and through the submission to the Board of a single detailed testing program covering each pool in its entirety. The Board, therefore requests that where possible this system be followed.

Questions regarding the above should be directed to R. A. Gowan at 261-8490 of the Board's Gas Department.

Dated at Calgary, Alberta on 7 April 1981.

H. J. Webber

H. J. Webber, P.Eng.
Manager, Gas Department

APPENDIX 1

11.103 (1) The licensee of a gas well, which, when completed, is not in a designated pool, shall obtain a subsurface static pressure measurement satisfactory to the Board using a properly calibrated gauge before any production is obtained other than during testing.

(2) The licensee of a gas well, which is completed in a designated pool from which production is regularly being taken, shall determine the stabilized shut-in reservoir pressure in each productive pool in the well every two years.

(3) Where a gas well is tested in accordance with subclause (2), the licensee shall ensure that a properly calibrated subsurface pressure gauge is used whenever liquid accumulation in the wellbore is known or suspected to be present.

(4) The licensee or a test coordinator representing the licensee shall supply to the Board, within one month from the date of the test, the data and results of each pressure measurement or determination required by this section.

(5) The Board may grant relief from any requirement of this section where special circumstances warrant.

11.120(1) (c) where the well is primarily productive of gas, one copy of each deliverability test including field notes, flow rate calculations, summary sheet (Form EG-32) and any supplementary data and calculations related to a proper interpretation of the test, and

11.130 (1) Any deliverability or other gas well test required by these regulations shall be conducted in accordance with the procedures described in the most recent edition of Board Guide G-3 (Gas Well Testing-Theory and Practice).

(2) Where a gas well is completed in more than one pool, the licensee of the gas well shall conduct deliverability or other required gas well tests on each producing pool in the gas well.

(3) Prior to the first regular production from a gas well in a pool where allowables are prescribed by Board order, the licensee shall test the well by a multi-point deliverability test using a properly calibrated subsurface pressure gauge.

(4) Prior to or during the first 90 days of production from a gas well in a pool where allowables are not prescribed by Board order, the licensee shall test the well by a multi-point deliverability test.

(5) The licensee of any producing gas well shall conduct a single-point deliverability test on the well during the second twelve-month period following the commencement of regular production.

(6) The Board may, upon its own motion or upon application therefor, grant relief from the provisions of subsections (4) and (5) hereof where the well is clearly of an infill type, or where the stabilized deliverability relationship of the well is to be obtained by some other test acceptable to the Board.

(7) Where a gas well is granted relief pursuant to subsection (6) hereto the licensee shall, prior to or during the first 90 days of regular production from the well, obtain the stabilized shut-in reservoir pressure of the well.

(8) Prior to or during the first 90 days of regular production from a gas well which has received any reservoir stimulation treatment or change in production equipment that will significantly alter its ability to deliver gas, the licensee shall test the well by a multi-point deliverability test.

(9) Where a gas well is tested in accordance with this section, the licensee shall ensure that a properly calibrated subsurface pressure gauge is used whenever liquid accumulation in the wellbore is known or suspected to be present during the conduct of the test.

(10) The Licensee or a test coordinator representing the licensee of a producing gas well which has been deliverability tested in accordance with previous clauses of this section, shall submit to the Board a schedule of testing which provides for the determination of absolute open flow potential either through a multi-point deliverability test or another test acceptable to the Board, every four years throughout the producing life of the well.

(11) The results of any gas well test required to be reported to the Board shall be reported by the licensee or an appointed test coordinator on either

(a) appropriate forms available from the Board, or

(b) such other forms as the Board may consider appropriate.

(12) The Board may, upon its own motion or upon application therefor, grant relief from any provisions of this section, but where the Board grants such relief and it may do so subject to such terms or conditions as it considers appropriate in the circumstances.

11.135 (1) Where a gas well is being cleaned up or tested, the amount of gas flared shall not exceed 600 thousand cubic metres including that produced during the initial clean-up period, unless the prior approval of the Board therefor has been obtained.

(2) Where a gas well is being cleaned up or tested, the flaring shall be minimized and be subject to section 7.060 of these regulations.

(3) The licensee of the well to be cleaned up or tested in accordance with this section shall notify the Board, through its appropriate area office, of the intention to perform such operations not less than three days prior to commencement of the operations.

CANADIANA
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JAN 22 1981

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

INFORMATIONAL LETTER
IL 81-3

TO: All Oil and Gas Operators

ASSESSMENT OF NATURAL GAS RESERVES, 1981
THE FREEHOLD MINERAL TAXATION ACT
THE OIL AND GAS CONSERVATION ACT

In order to determine the pool average well-head value of natural gas for the 1981 taxation year, the Assessor appointed under The Freehold Mineral Taxation Act and The Oil and Gas Conservation Act will require the information specified in this letter not later than March 31, 1981.

The procedure provides that the plant operator or, where the natural gas is not processed at a plant, the gas gathering system operator shall provide certain data to the Assessor as set out hereunder:

1. Where the raw gas produced requires further processing at a plant, the plant operator shall provide to the Assessor, for each pool serviced, a value for net revenue including

   (a) a value for residue gas sold for each pool at the price in effect on December 31, 1980. (The value shall include all rebates, and adjustments added to the well-head price as a consequence of the sale of gas beyond the Canadian border.),

   (b) values for plant products such as propane, butane, a mix of natural gas liquids, pentanes plus at the price in effect on December 31, 1980,

   (c) a value for sulphur calculated by multiplying annual production by a price of $45.00 per tonne, and

   (d) cost for gathering, compression prior to plant, and plant operating costs.

2. Where the produced raw gas does not require further processing at a plant, the gathering system operator shall provide to the Assessor, for each pool serviced, a value for net revenue including

(a) a value for gas sold at the price in effect on December 31, 1980. (This value shall include all rebates, and adjustments added to the well-head price as a consequence of the sale of gas beyond the Canadian border).

(b) values for any products such as pentanes plus recovered from the system which add significantly to the total value of the gas where such products can be attributed to specific pools, and

(c) cost for gathering and compression.

3. Some of the raw gas received at a plant and part of the residue gas and/or products are sometimes injected either into the pool of origin or into some other pool. If the material for injection is sold, then it should be included in the calculation of gross revenue, and the following additional data should be provided

(a) volumes of raw gas, residue gas or products injected,

(b) fields and pools from which produced and into which injected, and

(c) value of raw gas, residue gas or products injected.

Accordingly, for the 1981 taxation year each gas processing plant operator or gas gathering system operator is required to submit details of product values, cost of service and net revenue for the determination of well head values on a pool basis. The procedure to be used and an example submission and format are attached hereto. You are requested to adhere to this format as closely as possible. As indicated in the example, a breakdown between plant, field compression and gathering system costs is to be provided. The costs attributable to compressors located within plants would comprise part of the plant total. Each plant operator would, in addition to the required plant information, submit all of the field compressor and gathering system data pertaining to the plant operation even though these facilities may be operated by other owners. Please note also, that specific information is required for residue or raw gas injected.

In the case where gas gathering, field compression and sale occurs without subsequent processing, the operator of the gathering and compressor facilities shall submit the appropriate sales and cost data.

When a plant operator has no ownership interest in the pools which are serviced by the processing plant, and is purchasing raw gas at the well-head at a common price, the plant operator shall submit the data referred to in item 1, and shall, in addition supply the price which he was paying the well operators for the raw gas as at December 31, 1980.

Past experience has indicated that incomplete data or no data is received for some pools in which processing of the gas is not required, but gas gathering systems are necessary. It is in the owner's interest that cost of service be supplied in these cases.

The Assessor is aware that some of the information used in the compilation of these data may be of a confidential nature. Except for the net price used in the assessment calculation, the information supplied as required above will not be disclosed. Please note however, that the data submitted must include accurate information on both gross revenue and cost of service.

Any inquires regarding these matters should be directed to Mr. M. R. Blackadar, telephone number 261-8374, Mr. Dale Youngstrom, telephone number 261-3490, or Mr. Jim Heller, telephone 261-3490.

DATED at Calgary, Alberta on 19 January 1981

ENERGY RESOURCES CONSERVATION BOARD

M. R. Blackadar
Assessor

PROCEDURE FOR ESTABLISHING WELL HEAD GAS PRICES

To assure conformity in reporting and calculation of the well head price for each pool, we are requesting that the following information and basis be used. Where there is no processing plant, read "gas gathering system" in place of "plant".

1. The name of each field and pool

Note 1: fields and pools into which wells are placed for this purpose should be those designated for reporting purposes by the Energy Resources Conservation Board, as they existed as at December 31 of the base year (year just ended) for those wells. The assessor uses Board field and pool designations in determining the total production applicable to each pool. To calculate an accurate pool price it is essential that the net revenue supplied by the operator and the production supplied by the Board relate to identical groups of wells. In cases where the operator and the Board differ (which happen frequently), it is very time consuming and sometines impossible within the time limits provided, to locate where the differences lie.

Note 2: undefined wells as designated by the Board, should be considered separately and identified by the well location, rather than the pool code. If the gas produced from a number of undefined wells has approximately the same product composition, they may all be reported in one column under the heading "undefined" provided that the wells together with their individual gathered gas volumes are separately listed elsewhere in the report.

Note 3: when a well changes its pool designation during the year, its annual production should be assigned to the pool that it was part of on December 31. For example, a well which was designated as undefined until September was reclassified by the Board as a Viking well on September 15. The report should show all of the year's production from this well under the heading Viking Pool and the appropriate field.

2. The plant processing the gas, and the plant code assigned by the Board.

3. The plant operator.

4. Raw gas volume received at the plant and final products after processing for each pool in 1980 in SI Units.

   (a) Raw gas received at the plant in 10^3 m^3 at 101.325 kPa.

   *(b) Raw gas injected after receipt at plant - 10^3 m^3 at 101.325 kPa. Please identify field and pool into which injected, if known.

   *(c) Residue or marketable gas injected after receipt at plant - 10^3 m^3 at 101.325 kPa. Please identify field and pool into which injected, if known.

   (d) Sales gas, other than injected - 10^3 m^3 at 101.325 kPa.

   *(e) Propane injected - m^3. Please identify field and pool into which injected, if known.

   (f) Sales of propane, other than injected - m^3.

   *(g) Butanes injected - m^3. Please identify field and pool into which injected, if known.

   (h) Sales of butanes, other than injected - m^3.

   *(i) Pentanes plus injected - m^3. Please identify field and pool into which injected, if known.

   (j) Sales of pentanes plus, other than injected - m^3. Do not report field condensate reported on Board S-1 forms.

   *(k) N.G.L. other than above, injected - m^3. Please identify field and pool into which injected, if known.

   (l) Sales of N.G.L., other than injected - m^3.

   (m) Recovered sulphur - tonnes.

5. Gross value of products from pool - 1980. All values must be based on the price received for the product as at December 31, 1980, except sulphur which should be calculated on the basis of $45.00 per produced tonne. For sales gas, this price is made up of

   (i) the price received for the gas and

   (ii) the price adjustment as determined by the Minister for December 1980 pursuant to The Natural Gas Pricing Agreement Act.

*If not applicable omit

Note: In all instances the operator will use the best figures available to him for product prices on the assumption that this will be representative of the pool.

(a) Value of residue gas as at December 31, 1980. (Please list separately, "price received" and "price adjustment" as shown in the attached example).

  (i) residue gas sold to the market

  **(ii) residue gas injected. Depending on the circumstances, value may or may not be assigned to this item. Please refer to section 3 of the informational letter.

  **(iii) total of (i) and (ii).

(b) Value of propane as at December 31, 1980 (Please show unit price).

  (i) propane sold to the market

  **(ii) propane injected. See item (a) (ii) above.

  (iii) total of (i) and (ii).

(c) Value of butanes as at December 31, 1980. (Please show unit price.)

  (i) butanes sold to the market

  **(ii) butanes injected. See item (a) (ii) above.

  (iii) total of (i) and (ii).

(d) Value of pentanes plus as at December 31, 1980. (Please show unit price.)

  (i) pentanes plus sold to the market

  **(ii) pentanes plus injected. See item (a) (ii) above.

  (iii) total of (i) and (ii)

** Omit heading if value nil.

(e) Value of other N.G.L. as at December 31, 1980. (Please show unit price).

(i) N.G.L. sold to the market

**(ii) N.G.L. injected. See item (a) (ii) above.

(iii) total of (i) and (ii)

(f) Value of sulphur produced at $45.00 per tonne.

The sum of the above income streams is the gross value of the plant's share of the pool as at December 31, 1980.

6. 1980 cost of service of gathering, compressing and processing. Generally speaking, the cost of service principles, utilized by producers, in their submissions to the Department of Energy and Natural Resources (Department), for calculating deductions for gathering and processing gas for royalty purposes shall be used. Section 3 of the booklet issued by the Department entitled "Guidelines for the Calculation of Crown Royalty on Natural Gas and Associated By-products" may provide useful assistance to those who are not familiar with the procedure. As 1980 is the base year for a present value calculation, the cost of service should not take into consideration previous over or under deductions. For the purpose of this assessment, the cost of service of facilities required for cycling and load levelling are permitted deductions. As a well operating cost allowance will be used by the assessor, in addition to a cost of service deduction, consideration must be made in allocating only a proper share of field costs to gathering and field compression.

For purposes of prorating capital costs and operating expenses of a pool's share of facilities utilized, the same procedures as approved by the working interest owners and/or the Department should be used.

The "cost of service" permitted which has evolved using the general principles of the Jumping Pound Decision consists of:

** Omit heading if value nil.

(a) Direct operating cost of the pool's share of a facility. This may include operator's overhead consistent with that negotiated by participants in a joint venture and/or recognized by the Department.

(b) Rate of return on remaining invested capital - use 15% of the mid-term rate base of the pool's share of the facility. The mid-term rate base consists of

(i) average depreciated capital cost

(ii) working capital allowance (1/6 of direct operating cost)

(iii) land at cost

(c) Depreciation of the pool's share of the facility. A straight line depreciation is requested, in whatever percentage is appropriate for the facility. Four to five per cent appears to be the most popular range.

The sum of the individual costs of service for plant, gathering systems and compression is the 1980 cost of service for the pool.

7. The 1980 net revenue generation of the pool is the difference between the gross value (item 5) and the cost of service (item 6).

It is understood that this net revenue value relates only to the part of the pool production processed at a particular plant. Where two or more plants are involved in one pool, the assessor will sum the data submitted by each plant operator. The same is true of net revenues determined by gas gathering system operators, where more than one system is operated in a pool.

In addition, for those pools for which production of field condensate was reported, the gross revenue shall be adjusted by the assessor to take the value of condensate sales into consideration.

Note: Although this procedure relates to the information to be provided by the plant operators, it should be understood that where no processing plant is used, the gas gathering system operators or distributors should supply the necessary data.

** Omit heading if value nil.

Plant No. X

DATA SHEET - EXAMPLE FIELD COMPLEX
WELL HEAD VALUE

1981 ASSESSMENT
THE OIL AND GAS CONSERVATION ACT
THE FREEHOLD MINERAL TAXATION ACT

		Example A Pool	Example B Pool	Example C Pool	Example D Pool
1.	POOLS (both field and pool required - actual names and code nos.)				
2.	PLANT	Example Plant			
3.	PLANT OPERATOR	Example Company			
4.	VOLUMES* & PRODUCTS				
	a) Raw gas - plant inlet $10^3\ m^3$	197 415	107 118	338 482	165 409
	b) Raw gas injected $10^3\ m^3$		28 174[a]		
	c) Residue gas injected $10^3\ m^3$	56 348[b](to 'E' Pool)			
	d) Sales gas $10^3\ m^3$	118 555	65 843	277 204	124 577
	e) Propane injected, m^3	190[b](to 'E' Pool)		318[a]	
	f) Sales of propane, m^3	453	392	1 362	357
	g) Sales of butanes, m^3	1 870	1 137	5 465	1 255
	h) Sales of pentanes plus, m^3	11 998	7 353	39 327	8 295
	i) Recovered sulphur, tonnes	3 292	1 829	13 456	4 085

5 GROSS VALUE PRODUCTS FROM POOLS[c]

a) Gas Income $\$/10^3\ m^3$
(Unit Price) - 51.47
Price adjustment - 26.62
$78.09

	Example A Pool	Example B Pool	Example C Pool	Example D Pool
Sold to market	9 257 960	5 141 680	21 646 860	9 726 656
Injected	4 400 215			
	13 658 175	5 141 680	21 646 860	9 726 656

* - Gas volumes measured at 101.325 kPa and 15°C

a - injected to pool of origin and not sold

b - injected to pool 'E' and payment received

c - except for sulphur, for which a value of $45.00 per tonne must be used, the prices quoted in this example, are for illustrative purposes only.

	Example A Pool	Example B Pool	Example C Pool	Example D Pool
b) Propane Income $				
(Unit Price - $\$64.78/\text{m}^3$)				
Sold to Market	29 345	25 394	88 230	23 126
Injected	12 308			
	41 653	25 394	88 230	23 126
c) Butanes Income $				
(Unit Price - $\$104.27/\text{m}^3$)				
Sold to market	194 985	118 555	569 836	130 859
d) Pentanes Plus Income $				
(Unit Price - $\$87.68/\text{m}^3$)				
Sold to Market	1 051 985	644 711	3 448 191	727 306
e) Sulphur Income $ at $45.00/tonne	148 152	82 296	605 520	183 840
GROSS VALUE	15 094 950	6 012 636	26 358 637	10 791 787
6. COST OF SERVICE - All figures in Thousands of Dollars				
a) Cumulative Capital & Mid-term Rate Base				
i) Plant Capital		11 106		
Mid-term Rate Base		9 781		
ii) Compression Capital				196
Mid-term Rate Base				181
iii) Gathering System Capital	265	230	1 164	248
Mid-term Rate Base	222	205	1 036	231
b) Cost of Service				
i) Cost of Service				
Plant - Operating		1 501		
Depreciation (4% S.L.*)		444		
Return on Rate Base (15%)		1 467		
		3 412		
Plant Split**	929	350	1 472	661

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* Straight line depreciation must be used. Percentage used must not vary from year to year.

** Residue Gas was used in the example as the basis for the plant split for purposes of simplicity. Actual split of plant costs should be made on the basis of the plant operator's knowledge of the costs involved for each pool.

	Example A Pool	Example B Pool	Example C Pool	Example D Pool
ii) Compression				
Operating Costs				2
Depreciation (4% S.L.*)				8
Return on Rate Base (15%)				27
				37
iii) Gathering System				
Operating Costs	18	51	50	20
Depreciation (4% S.L.*)	11	9	47	10
Return on Rate Base (15%)	33	31	155	35
	62	91	252	65
iv) Total Cost of Service	991	441	1,724	763
7. 1980 NET REVENUE 5-6	14 104	5 572	24 635	10 029

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* Straight line

[illegible]
[illegible] 26 1981

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

INFORMATIONAL LETTER
IL 81-4

TO: Crude Oil Shippers
Crude Oil Producers

MONTHLY DEMAND ORDERS DURING
CUTBACK PERIOD

During the period when oil production may be reduced under the provision of Order in Council 1078/80 the Board will continue to issue a monthly MD Order. It will continue to request nominations for Alberta oil and hold a monthly nomination hearing. In setting allowables, the Board will not take into account any cut-back imposed under Order in Council 1078/80 and under normal circumstances will assume the market demand is sufficient to require all of Alberta's light and medium crude oil productive capacity. Should the Board be satisfied, in a particular month, that the demand for Alberta oil would have been less than the productive capacity had the cut-back in production not been in effect, then it would prorate that demand among pools in the province in the normal manner.

DATED at Calgary, Alberta on
18 February 1981

Vernon Millard

Vernon Millard

Chairman

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ENERGY RESOURCES CONSERVATION BOARD
Calgary, Alberta

Informational Letter
IL 81-5

TO: All Oil and Gas Operators

ANNUAL REVIEW OF CRUDE OIL RESERVES

For the 1980 year-end crude oil reserves review, the Oil Department staff reviewed the established reserve values for those crude oil pools where additional drilling had taken place or production data showed that a revision was necessary. As a result, the Board plans to amend its estimate of reserves for the pools as shown on Attachment I and to implement these revisions in the 1980 year-end reserves report. The reserve adjustments will be reflected for allowable purposes effective 1 May 1981.

If an operator disagrees with the initial established reserves as proposed on Attachment I, a letter of objection must be submitted on or before 31 March 1981 marked for the attention of A. R. Olive, Staff Specialist, Oil Department. Where an objection is received, the Board will not make the reserve change proposed by its staff, but rather will arrange a schedule for filing of an incremental reserves submission in accordance with Informational Letter IL-OG 76-23.

Listed in Attachment II are the oil pools which became non-confidential, resumed production, were redesignated, or were changed as a result of operator and Oil Department reservoir studies completed during 1980.

Listed in Attachment III are schemes which received enhanced recovery recognition during 1980 pursuant to applications for enhanced recovery schemes.

Listed in Attachment IV are enhanced recovery reserves established on the basis of applications for enhanced recovery schemes approved in 1980. These reserves are classified as "pre-booked" since they will not be assigned until the schemes are fully operational and have qualified for enhanced recovery status.

ISSUED at Calgary, Alberta on 25 February 1981.

ENERGY RESOURCES CONSERVATION BOARD

J. A. Bray, P. Eng.
Manager, Oil Department

Attachments

ATTACHMENT I

PROPOSED RESERVE CHANGE

	Current		Proposed		
Pool Light and Medium Crude Oil	Initial Vol. in Pl. $10^3\ m^3$	Initial Est. Res. $10^3\ m^3$	Initial Vol. in Pl. $10^3\ m^3$	Initial Est. Res. $10^3\ m^3$	Remarks
Acheson Blairmore G*	97.3	11.6	97.3	14.6	Increase Ri** - Np** approaching RiN**
Acheson East Blairmore B	4 770.0	334.0	6 750.0	460.0	Increase OIP** - New wells added
Bashaw Ireton A*	416.0	20.8	416.0	25.0	Increase Ri - Np approaching RiN
Bonanza Boundary A	1 950.0	195.0	2 850.0	285.0	Increase OIP - New Wells added
Brazeau River Lower Mannville C	736.0	73.6	736.0	0.8	Pool suspended - Set RiN = Np
Campbell-Namao Blairmore J	933.0	93.3	1 110.0	100.0	Increase OIP; Decrease Ri - New wells added
Chain Viking A	134.0	13.4	207.0	31.0	Increase OIP & Ri - Np approaching RiN
Chigwell Viking B (Primary)	550.0	66.0	1 400.0	168.0	Increase OIP - New wells added
Chigwell Mannville E	5 500.0	495.0	7 040.0	634.0	Increase OIP - New wells added
Chigwell Upper Mannville A	666.0	53.3	1 260.0	101.0	Increase OIP - New wells added
Chigwell Upper Mannville B	275.0	27.5	275.0	8.3	Decrease Ri - Performance
Chigwell D-2A*	216.0	36.7	216.0	43.2	Increase Ri - Np approaching RiN
Clive D-3A (Primary)	610.0	36.4	610.0	48.8	Increase Ri - Np approaching RiN
Davey D-2B	278.0	55.6	278.0	2.0	Pool abandoned - Set RiN = Np
Edson Cardium C	2 200.0	220.0	2 200.0	110.0	Decrease Ri - Performance
Fenn-Big Valley D-3F	2 370.0	1 650.0	2 530.0	1 900.0	Increase OIP & Ri - Np approaching RiN
Gilby Viking E*	700.0	77.0	700.0	84.0	Increase Ri - Np approaching RiN

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* Pools Subject to Good Production Practice

** Abbreviations

Ri - Recovery Factor
Np - Cumulative Oil Production
RiN - Recoverable Reserves
OIP - Initial Volume-in-Place

ATTACHMENT I (CONT'D)

PROPOSED RESERVE CHANGE

	Current		Proposed		
Pool Light and Medium Crude Oil	Initial Vol. in Pl. 10^3 m^3	Initial Est. Res. 10^3 m^3	Initial Vol. in Pl. 10^3 m^3	Initial Est. Res. 10^3 m^3	Remarks
Gilby Basal Mannville S*	90.0	9.0	294.0	20.6	Increase OIP; Decrease Ri - Np approaching RiN
Golden Spike D-3C*	408.0	143.0	425.0	170.0	Increase OIP & Ri - Np approaching RiN
Keho Bow Island C	345.0	34.5	345.0	10.4	Decrease Ri - Performance
Killam Upper Viking C	44.8	2.2	44.8	4.5	Increase Ri - Np approaching RiN
Leduc-Woodbend D-2E*	192.0	110.0	192.0	113.0	Increase Ri - Np approaching RiN
Leduc-Woodbend D-3A	52 900.0	37 000.0	54 900.0	38 400.0	Increase OIP - Np approaching RiN
Leduc-Woodbend D-3E	310.0	15.6	310.0	2.6	Pool suspended - Set RiN = Np
Lone Pine Creek D-2A	96.3	14.5	96.3	24.0	Increase Ri - Np approaching RiN
Medicine River Glauc D & Ostracod M*	386.0	38.6	533.0	80.0	Increase OIP & Ri - Np approaching RiN
Muskeg Cardium A	319.0	31.9	1 630.0	163.0	Increase OIP - New wells added
Nevis Blairmore C*	852.0	85.2	1 470.0	147.0	Increase OIP - New wells added
Nevis Upper Mannville A	1 270.0	127.0	1 900.0	152.0	Increase OIP; Decrease Ri - New wells added
Nipisi Gilwood C (Primary)	528.0	106.0	249.0	50.0	Decrease OIP & Ri - Performance
Niton Basal Quartz B (Primary)	0.0	0.0	62.3	14.3	Establish primary reserves
Normandville D-1A*	531.0	149.0	531.0	170.0	Increase Ri - Np approaching RiN
Normandville D-3A*	412.0	207.0	412.0	169.0	Decrease Ri - Performance
Oberlin Mannville C*	197.0	19.7	197.0	7.9	Decrease Ri - Performance
Pembina Cardium Proj.No. 56*	-	953.0	9 200.0	550.0	Re-evaluation - Increase RiN - Np approaching RiN
Pembina Cardium Proj.No. 62*			9 650.0	965.0	

ATTACHMENT I (CONT'D)

PROPOSED RESERVE CHANGE

Pool Light and Medium Crude Oil	Current Initial Vol. in Pl. 10^3 m^3	Current Initial Est. Res. 10^3 m^3	Proposed Initial Vol. in Pl. 10^3 m^3	Proposed Initial Est. Res. 10^3 m^3	Remarks
Provost Viking V	113.0	4.5	113.0	11.3	Increase Ri - Np approaching RiN
Provost Blairmore*	1 350.0	135.0	1 630.0	163.0	Increase OIP - Np approaching RiN
Provost Mannville I	421.0	12.6	745.0	22.4	Increase OIP - New wells drilled
Provost Cummings A	564.0	56.4	957.0	95.7	Increase OIP - New wells added
Retlaw Mannville II	288.0	28.8	288.0	8.6	Decrease Ri - Performance
St. Albert-Big Lake D-2A	397.0	238.0	426.0	277.0	Increase OIP & Ri - Np approaching RiN
Stettler North Upper Mannville A	399.0	39.9	468.0	46.8	Increase OIP - New wells added
Swalwell D-2A	1 730.0	642.0	1 730.0	190.0	Decrease Ri - Performance
Sylvan Lake Cardium B	30.4	3.0	51.0	5.1	Increase OIP - Np approaching RiN
Turner Valley Rundle*	159 000.0	20 700.0	159 000.0	21 700.0	Increase Ri - Np approaching RiN
Virginia Hills BHL (Primary)	1 140.0	262.0	1 830.0	421.0	Increase OIP - Np approaching RiN
Virgo Muskeg C	127.0	31.8	160.0	40.0	Increase OIP - Np approaching RiN
Wayne-Rosedale Glauc M	435.0	43.5	435.0	4.4	Decrease Ri - Performance
Willesden Green Belly River L	307.0	30.7	307.0	9.2	Decrease Ri - Performance
Willesden Green Viking A	1 150.0	173.0	1 550.0	233.0	Increase OIP - New wells added
Windfall D-3A*	10 200.0	1 530.0	10 200.0	2 040.0	Increase Ri - Np approaching RiN
Zama Muskeg J	99.3	19.9	150.0	30.0	Increase OIP - Np approaching RiN
Heavy Crude Oil					
Alderson Upper Mannville B	154.0	6.2	154.0	9.2	Increase Ri - Np approaching RiN

ATTACHMENT I (CONT'D)

PROPOSED RESERVE CHANGE

	Current		Proposed		
Pool Heavy Crude Oil	Initial Vol. in Pl. 10^3 m^3	Initial Est. Res. 10^3 m^3	Initial Vol. in Pl. 10^3 m^3	Initial Est. Res. 10^3 m^3	Remarks
Alderson Upper Mannville L	85.0	8.5	130.0	13.0	Increase OIP - Np approaching RiN
Alderson Lower Mannville A*	477.0	95.3	550.0	110.0	Increase OIP - Np approaching RiN
Bantry Mannville G*	477.0	47.7	752.0	75.2	Increase OIP - Np approaching RiN
Berry Lower Mannville A*	385.0	15.4	697.0	27.9	Increase OIP - New wells added
Bigoray Pekisko A*	1 240.0	62.0	3 320.0	100.0	Increase OIP - Pool development
Chauvin Mannville A (Primary)	159.0	7.9	341.0	17.0	Increase OIP - Np approaching RiN
Chauvin South Sparky E (Primary)	900.0	63.4	1 780.0	125.0	Increase OIP - New wells added
Chauvin South Lloydminster C*	777.0	77.7	1 320.0	132.0	Increase OIP - Np approaching RiN
Chauvin South Lloydminster G	267.0	13.4	900.0	45.0	Increase OIP - New wells added
Esther Upper Mannville B	337.0	16.8	865.0	51.9	Increase OIP & Ri - Np approaching RiN
Grand Forks Lower Mannville A*	904.0	90.4	1 660.0	249.0	Increase OIP & Ri - New wells added
Grand Forks Lower Mannville B*	1 020.0	153.0	676.0	101.0	Re-evaluation - Decrease OIP
Grand Forks Lower Mannville C*	1 470.0	147.0	1 470.0	176.0	Increase Ri - Np approaching RiN
Hays Lower Mannville G	54.0	5.4	108.0	13.0	Increase OIP & Ri - Np approaching RiN
Hayter Sparky A (Primary)	326.0	22.8	376.0	26.3	Increase OIP - New wells added
Hayter Dina A	1 580.0	79.0	2 120.0	84.8	Increase OIP; Decrease Ri New wells added
Hayter Dina B	5 120.0	102.0	17 000.0	340.0	Increase OIP - New wells added
Jenner Upper Mannville F*	3 810.0	114.0	4 260.0	170.0	Increase OIP & Ri - New wells added

ATTACHMENT I (CONT'D)

PROPOSED RESERVE CHANGE

Pool Heavy Crude Oil	Current Initial Vol. in Pl. 10^3 m^3	Current Initial Est. Res. 10^3 m^3	Proposed Initial Vol. in Pl. 10^3 m^3	Proposed Initial Est. Res. 10^3 m^3	Remarks
Lloydminster Colony F	45.0	2.3	180.0	9.0	Increase OIP - Np approaching RiN
Lloydminster Sparky B (Primary)	7 530.0	421.0	10 900.0	545.0	Increase OIP; Decrease Ri - New wells added
Lloydminster Sparky G	7 120.0	356.0	9 300.0	465.0	Increase OIP - New wells added
Marwayne Sparky A	1 130.0	33.9	1 680.0	50.4	Increase OIP - New wells added
Morgan Sparky A	780.0	23.4	3 570.0	107.0	Increase OIP - New wells added
Morgan Lloydminster A	1 780.0	18.0	19 200.0	192.0	Increase OIP - New wells added
Reagan Rundle A	318.0	63.6	350.0	70.0	Increase OIP - Np approaching RiN
Ribstone Sparky A	1 470.0	88.2	2 200.0	110.0	Increase OIP: Decrease Ri - New wells added
Sibbald Upper Mannville C	1 250.0	62.5	2 660.0	133.0	Increase OIP - New wells added
Skiff Sawtooth A	400.0	16.0	400.0	20.0	Increase Ri - Np approaching RiN
Vermilion Sparky A*	6 760.0	487.0	10 500.0	565.0	Re-evaluation - Increase OIP; Decrease Ri - Pool development
Wildmere General Petroleum A	251.0	5.0	251.0	7.5	Increase Ri - Np approaching RiN
Wildmere Lloydminster C	994.0	29.8	1 140.0	34.2	Increase OIP - New wells added

ATTACHMENT II

NON-CONFIDENTIAL POOLS DECLARED OR REDESIGNATED AFTER 31 DECEMBER 1979 AND OTHER POOLS FOR WHICH RESERVE DATA WERE CHANGED AFTER 31 DECEMBER 1979

Pool Light and Medium Crude Oil	Initial Established Crude Oil At 31 Dec. 1979 $10^3\ m^3$	 At 31 Dec. 1980 $10^3\ m^3$	Change $10^3\ m^3$	Reason for Change
Acheson Blairmore K	2.5	25.3	+22.8	Resumed Production Operations
Aerial Viking A	conf	27.5	-	Lost confidential status 1 April 1980
Aerial Mannville	200.0	254.0	+54.0	Re-evaluation - Enhanced Recovery Pool
Aerial Mannville B	0.0	16.7	+16.7	New Pool 1 June 1980
Aerial Mannville C	0.0	61.8	+61.8	New Pool 1 August 1980
Ante Creek North Peace River D	conf	0.1	-19.7	Lost confidential status 1 January 1980 - Suspended
Bellshill Lake Blairmore E	undef	16.6	-	New Pool 1 January 1980
Bigoray Cardium B	conf	258.0	-	Lost confidential status 1 January 1980
Bigoray Lower Mannville A	undef	44.3	+23.1	New Pool 1 July 1980
Bigoray Lower Mannville B	0.0	22.7	+22.7	New Pool 1 September 1980
Bigoray Lower Mannville C	0.0	14.2	+14.2	New Pool 1 October 1980
Bigoray Ostracod B*	16.1	2.9	-13.2	Pool suspended - Set RiN = Np
Bigoray Ellerslie A	0.0	26.6	+26.6	New Pool 1 January 1980
Bigoray Ellerslie B	0.0	27.7	+27.7	New Pool 1 September 1980
Bigoray Nisku B	390.0	450.0	+60.0	Re-evaluation - Increased OIP
Bigoray Nisku D	880.0	1 100.0	+220.0	Enhanced recovery recognition
Bigoray Nisku G	conf	338.0	+113.0	Enhanced recovery recognition
Bigoray Nisku H	conf	660.0	+210.0	Re-evaluation - Increased OIP
Bigoray Nisku I	98.0	183.0	+85.0	Enhanced recovery recognition
Bigoray Nisku J	undef	12.3	-	Lost confidential status 1 May 1980
Blackfoot Lower Mannville A	undef	21.2	+6.1	New Pool 1 March 1980
Boundary Lake South Triassic F	0.2	5.0	+4.8	Resumed production operations

	Initial Established Crude Oil			
Pool Light and Medium Crude Oil	At 31 Dec. 1979 10^3 m^3	At 31 Dec. 1980 10^3 m^3	Change 10^3 m^3	Reason for Change
Boundary Lake South Triassic H	240.0	672.0	+432.0	Enhanced recovery recognition
Boundary Lake South Triassic I	42.4	47.6	+5.2	Re-evaluation - Increased OIP
Brazeau River Belly River A	0.0	9.4	+9.4	New Pool 1 March 1980
Brazeau River Nisku B	636.0	920.0	+284.0	Re-evaluation - Increased OIP
Brazeau River Nisku I	280.0	369.0	+89.0	Re-evaluation - Increased OIP
Bruce Lower Mannville I	0.0	18.6	+18.6	New Pool 1 November 1980
Byemoor Viking A	conf	14.4	-	Lost confidential status 1 October 1980
Caroline Viking A	1 110.0	1 180.0	+70.0	Re-evaluation - Increased OIP Decreased Ri
Caroline Viking H	0.0	8.2	+8.2	New Pool 1 June 1980
Caroline Viking I	0.0	21.0	+21.0	New Pool 1 October 1980
Carrot Creek Lower Mannville B	0.0	22.1	+22.1	New Pool 1 August 1980
Carrot Creek Jurassic A	0.0	21.3	+21.3	New Pool 1 February 1980
Carson Creek North BHL B	19 900.0	20 100.0	+200.0	Re-evaluation - Enhanced recovery pool
Cherhill Banff D	conf	415.0	+142.0	Lost confidential status 1 October 1980
Chigwell Upper Mannville C	0.0	26.1	+26.1	New Pool 1 June 1980
Coutts Moulton A	535.0	598.0	+63.0	Re-evaluation - Enhanced recovery pool
Cyn-Pem Nisku A	120.0	214.0	+94.0	Enhanced recovery recognition
Drumheller Mannville Z	conf	7.5	-	Lost confidential status 1 January 1980
Drumheller Mannville AA	0.0	28.6	+28.6	New Pool 1 February 1980
Drumheller Banff B	undef	7.1	-	Lost confidential status 1 November 1980
Edson Cardium H	0.9	30.8	+29.9	Re-evaluation - Pool suspended in error

	Initial Established Crude Oil			
Pool Light and Medium Crude Oil	At 31 Dec. 1979 $10^3\ m^3$	At 31 Dec. 1980 $10^3\ m^3$	Change $10^3\ m^3$	Reason for Change
Edson Bluesky A	undef	43.0	-	Lost confidential status 1 October 1980
Erskine Blairmore F	conf	19.2	-	Lost confidential status 1 January 1980
Fenn Big Valley D-2B	10.0	0.9	-9.1	Pool suspended - Set RiN = Np
Ferrier Belly River B	42.7	26.0	-16.7	Re-evaluation - Decreased OIP
Ferrier Cardium D	1 920.0	3 470.0	+1 550.0	Re-evaluation - Enhanced recovery pool
Ferrier Cardium G	1 480.0	3 410.0	+1 930.0	Re-evaluation - Enhanced recovery pool
Ferrier Viking B	0.0	9.7	+9.7	New Pool 1 March 1980
Fire Keg River A	6.1	25.6	+19.5	Resumed production operations
Fox Creek Gething B	0.0	66.8	+66.8	New Pool 1 December 1980
Fox Creek BHL A	75.0	375.0	+300.0	Enhanced recovery recognition
Garrington Cardium D	conf	40.0	-	Lost confidential status 1 October 1980
Garrington Viking A	undef	136.0	+27.2	New Pool 1 June 1980
Garrington Lower Mannville E	0.0	40.3	+40.3	New Pool 1 May 1980
Garrington Elkton-Shunda A	0.0	5.3	+5.3	New Pool 1 March 1980
Ghost Pine Pekisko K	0.0	30.5	+30.5	New Pool 1 February 1980
Gilby Belly River C	0.0	48.5	+48.5	New Pool 1 April 1980
Gilby Basal Mannville B	2 400.0	1 670.0	-730.0	Re-evaluation - Enhanced recovery pool
Gilby Nisku A	conf	24.2	-	Lost confidential status 1 August 1980
Giroux Lake Gething A	conf	7.0	-	Lost confidential status 1 November 1980
Gladys Lower Mannville A	conf	394.0	-	Lost confidential status 1 January 1980
Gladys Lower Mannville B	conf	7.8	-	Lost confidential status 1 January 1980
Gladys Rundle C	conf	170.0	+57.8	Re-evaluation - Coalescence of Rundle A, B & C Pools

Pool Light and Medium Crude Oil	Initial Established Crude Oil At 31 Dec. 1979 10^3 m^3	At 31 Dec. 1980 10^3 m^3	Change 10^3 m^3	Reason for Change
Gladys Rundle E	undef	41.9	-	New Pool 1 August 1980
Halkirk Lower Mannville C	0.0	46.5	+46.5	New Pool 1 June 1980
Harmattan East Cardium A	0.0	15.9	+15.9	New Pool 1 March 1980
Harmattan East Cardium B	0.0	15.2	+15.2	New Pool 1 November 1980
Harmattan East Viking A	0.0	7.0	+7.0	New Pool 1 July 1980
Hatton Mississippian A	undef	9.8	-	New Pool 1 March 1980
Highvale Lower Mannville A	168.0	540.0	+372.0	Enhanced recovery recognition
Highvale Lower Mannville B	conf	12.0	-	Lost confidential status 1 April 1980
Highvale Banff B	74.1	14.4	-59.7	Re-evaluation - Decreased OIP & Ri
Highvale Banff C	0.0	6.2	+6.2	New Pool 1 January 1980 - Previously part of B Pool
Highvale Banff D	0.0	5.0	+5.0	New Pool 1 January 1980 - Previously part of B Pool
Hussar Glauconitic MM	34.6	50.3	+15.7	Re-evaluation - Increased OIP
Hussar Glauconitic SS	0.0	17.3	+17.3	New Pool 1 February 1980
Hussar Glauconitic TT	0.0	6.9	+6.9	New Pool 1 March 1980
Hussar Glauconitic VV	0.0	21.6	+21.6	New Pool 1 April 1980
Hussar Glauconitic WW	undef	37.1	-	New Pool 1 August 1980
Hussar Glauconitic XX	0.0	13.8	+13.8	Lost confidential status 1 December 1980
Joarcam Viking	15 000.0	15 900.0	+900.0	Re-evaluation - Enhanced recovery pool
Josephine Kiskatinaw B	undef	14.9	-	New Pool 1 January 1980
Jumpbush Upper Mannville C	conf	42.9	-	Lost confidential status 1 April 1980
Jumpbush Upper Mannville D	0.0	31.9	+31.9	New Pool 1 February 1980
Kakwa Main Cardium A	conf	50.0	-	Lost confidential status 1 December 1980
Kakwa A Cardium A	31.7	135.0	+103.3	Re-evaluation - Increased OIP & Ri

Pool Light and Medium Crude Oil	Initial Established Crude Oil At 31 Dec. 1979 10^3 m^3	 At 31 Dec. 1980 10^3 m^3	Change 10^3 m^3	Reasons for Change
Kakwa C Cardium A	conf	37.8	+22.8	Lost confidential status 1 July 1980 - Increased OIP
Kaybob South Dunvegan B	0.0	10.2	+10.2	New Pool 1 July 1980
Kaybob South Dunvegan C	0.0	33.9	+33.9	New Pool 1 October 1980
Killam Upper Viking E	conf	7.0	-	Lost confidential status 1 July 1980
Killam Glauconitic S	0.0	31.4	+31.4	New Pool 1 August 1980
Larne Muskeg B	6.1	14.4	+8.3	Resumed production operations
Larne Keg River P	10.5	34.6	+24.1	Resumed production operations
Malmo D-3D	conf	48.0	-	Lost confidential status 1 October 1980
Manyberries Sunburst Q	118.0	293.0	+175.0	Re-evaluation - Increased OIP & Ri
Medicine River Viking B	conf	21.2	+18.6	Lost confidential status 1 September 1980 - Increased OIP & Ri
Medicine River Glauconitic A	2 020.0	2 050.0	+30.0	Re-evaluation - Enhanced recovery pool
Mikwan Lower Mannville B	0.0	52.0	+52.0	Lost confidential status 1 October 1980
Minnehik-Buck Lake Cardium B	0.0	17.1	+17.1	New Pool 1 February 1980
Minnehik-Buck Lake Cardium C	0.0	13.6	+13.6	New Pool 1 February 1980
Muskeg Cardium B	46.3	97.5	+51.2	Re-evaluation - Increased OIP, Decreased Ri
Nipisi Gilwood A	47 100.0	48 200.0	+1 100.0	Re-evaluation - Enhanced recovery pool
Nipisi Gilwood D	0.0	11.7	+11.7	New Pool 1 August 1980
Nipisi Keg River Sand C	12.0	58.8	+46.8	Re-evaluation - Increased OIP
Nipisi Keg River Sand E	0.0	85.8	+85.8	New Pool 1 February 1980
Parflesh Lower Mannville C	14.0	575.0	+246.0	Re-evaluation - Coalesced A & C Pools Enhanced recovery pool
Peco Cadomin B	0.0	10.8	+10.8	New Pool 1 September 1980
Peco North Cardium A	0.0	1.9	+1.9	New Pool 1 January 1980

ATTACHMENT II (CONT'D)

	Initial Established Crude Oil			
Pool Light and Medium Crude Oil	At 31 Dec. 1979 $10^3\ m^3$	At 31 Dec. 1980 $10^3\ m^3$	Change $10^3\ m^3$	Reasons for Change
Pembina Keystone Belly River U	1 230.0	2 130.0	+900.0	Re-evaluation - Enhanced recovery pool
Pembina Belly River YY	10.5	59.5	+49.0	Re-evaluation - Increased OIP
Pembina Belly River FFF & GGG	240.0	240.0	-	Re-evaluation - Commingled FFF & GGG Pools
Pembina Belly River HHH	0.0	55.2	+55.2	New Pool 1 March 1980
Pembina Belly River III	0.0	15.2	+15.2	New Pool 1 May 1980
Pembina Keystone Ellerslie A	148.0	120.0	-24.0	Re-evaluation - Increased Ri; Decreased OIP
Pembina Jurassic A	0.0	69.0	+69.0	New Pool 1 May 1980
Pembina Nisku C	429.0	715.0	+286.0	Enhanced recovery recognition
Pembina Nisku I	24.0	74.0	+50.0	Re-evaluation - Increased OIP
Pembina Nisku J	420.0	564.0	+144.0	Enhanced recovery recognition
Pembina Nisku K	840.0	972.0	+132.0	Re-evaluation - Increased OIP
Pembina Nisku L	1 000.0	1 680.0	+680.0	Re-evaluation - Increased Ri & OIP
Pembina Nisku M	conf	1 140.0	-	Lost confidential status 1 March 1980
Pembina Nisku N	conf	560.0	-	Lost confidential status 1 August 1980
Pembina Nisku O	conf	680.0	-860.0	Lost confidential status 1 September 1980 - Decreased OIP
Pembina Nisku P	conf	1 600.0	+410.0	Lost confidential status 1 August 1980
Provost Viking CC	5.7	5.7	0.0	Previously Red Willow Viking K Pool
Provost Mannville CC	0.0	10.2	+10.2	New Pool 1 July 1980
Provost Lloydminster A	conf	68.4	-	Lost confidential status 1 August 1980
Provost Cummings B	conf	6.3	-	Lost confidential status 1 March 1980
Rainbow South Muskeg F	44.8	0.2	-44.6	Pool Abandoned - Set RiN = Np
Rainbow South Keg River N	1 000.0	480.0	-520.0	Re-evaluation - Decreased OIP

Pool	Initial Established Crude Oil			
Light and Medium Crude Oil	At 31 Dec. 1979 10^3 m^3	At 31 Dec. 1980 10^3 m^3	Change 10^3 m^3	Reasons for Change
Rainbow South Keg River O	conf	350.0	-98.0	Lost confidential status 1 March 1980 - Decreased OIP
Red Earth Slave Point A	562.0	582.0	+20.0	Re-evaluation - Enhanced recovery pool
Red Earth Slave Point I	25.9	55.9	+30.0	Re-evaluation - Coalescence of Slave Point H & I pools
Red Earth Granite Wash P	conf	19.8	-	Lost confidential status 1 September 1980
Redwater Upper, Middle & Lower Viking A	11.2	170.0	+158.8	Re-evaluation - Coalesced with C Pool
Redwater Basal Mannville G	0.0	63.7	+63.7	New Pool 1 February 1980
Redwater Basal Mannville H	0.0	18.2	+18.2	New Pool 1 July 1980
Redwater Basal Mannville I	0.0	26.6	+26.6	New Pool 1 May 1980
Redwater Basal Mannville J	0.0	24.3	+24.3	New Pool 1 August 1980
Ricinus Cardium DD	0.0	35.9	+35.9	New Pool 1 September 1980
Seal Granite Wash A	0.0	56.1	+56.1	New Pool 1 March 1980
Seiu Lake Lower Mannville G	43.7	77.6	+33.9	Re-evaluation - Increased OIP
Shekilie Keg River H	conf	372.0	-	Lost confidential status 1 March 1980
Shekilie Keg River I	conf	333.0	-	Lost confidential status 1 August 1980
Shekilie Keg River J	0.0	136.0	+136.0	New Pool 1 May 1980
Sounding Upper Mannville D*	undef	10.8	-	New Pool 1 August 1980
Stanmore Upper Mannville A & C	6.0	0.4	-5.6	Pool suspended - Set RiN = Np
Stettler D-2C	0.0	46.5	+46.5	New Pool 1 October 1980
Stettler South D-2	238.0	288.0	+50.0	Re-evaluation - Increased Ri
Sunset Triassic A	1 030.0	1 120.0	+90.0	Enhanced recovery recognition

Pool Light and Medium Crude Oil	Initial Established Crude Oil At 31 Dec. 1979 10^3 m^3	At 31 Dec. 1980 10^3 m^3	Change 10^3 m^3	Reasons for Change
Swalwell Pekisko F	conf	109.0	+29.6	Lost confidential status 1 December 1980 - Increased OIP
Sylvan Lake Glauconitic C	20.2	18.4	-1.8	Pool suspended - Set RiN = Np
Sylvan Lake Ostracod F	conf	14.4	-	Lost confidential status 1 March 1980
Twining Lower Mannville B	553.0	372.0	-181.0	Re-evaluation - Enhanced recovery pool
Utikuma Lake Keg River Sandstone N	565.0	870.0	+305.0	Re-evaluation - Coalescence of Keg River Sandstone N & Q Pools
Utikuma Lake Keg River Sandstone O	conf	110.0	+41.5	Lost confidential status 1 September 1980 - Increased OIP
Utikuma Lake Keg River Sandstone P	conf	74.0	-	Lost confidential status 1 September 1980
Utikuma Lake Keg River Sandstone R	0.0	31.3	+31.3	New Pool 1 April 1980
Virginia Hills BHL (Waterflood)	29 600.0	24 800.0	-4 800.0	Re-evaluation - Reduced Ri - Waterflood area
Virgo Muskeg E	11.9	11.6	-0.3	Pool suspended - Set RiN = Np
Virgo Muskeg O	0.0	69.3	+69.3	New Pool 1 June 1980
Virgo Keg River P	31.6	52.5	+20.9	Resumed production operations
Virgo Keg River RRR	83.4	35.8	-47.6	Pool suspended - Set RiN = Np
Virgo Keg River SSS	2.2	59.5	+57.3	Resumed production operations
Virgo Keg River C2C	27.8	79.4	+51.6	Resumed production operations
Virgo Keg River J2J	8.4	3.4	-5.0	Pool suspended - Set RiN = Np
Wayne-Rosedale Glauc N	0.0	8.5	+8.5	New Pool 1 September 1980
Wayne-Rosedale Basal Quartz AA	conf	49.8	-	Lost confidential status 1 August 1980
Wayne-Rosedale Basal Quartz BB	0.0	35.7	+35.7	New Pool 1 March 1980
Wayne-Rosedale Basal Quartz CC	0.0	47.3	+47.3	New Pool 1 March 1980
Wayne-Rosedale Basal Quartz DD	0.0	54.9	+54.9	New Pool 1 March 1980

	Initial Established Crude Oil			
Pool Light and Medium Crude Oil	At 31 Dec. 1979 10^3 m^3	At 31 Dec. 1980 10^3 m^3	Change 10^3 m^3	Reasons for Change
Wayne-Rosedale Basal Quartz FF	0.0	15.6	+15.6	New Pool 1 August 1980
Wembley Halfway B	conf	750.0	+604.2	New Pool 1 October 1980 - Coalesced with Halfway A Pool
Westpem Nisku C	conf	1 600.0	-	Lost confidential status 1 February 1980
Westpem Nisku D	conf	800.0	-36.0	Lost confidential status 1 August 1980 - Decreased OIP
Willesden Green Belly River H	41.2	16.7	-24.5	New Pool 1 May 1980 - Previously part of B Pool - Decreased OIP & Ri
Willesden Green* Cardium A	37 000.0	36 800.0	-200.0	Re-evaluation - Enhanced recovery pool
Willesden Green Cardium F	0.0	15.5	+15.5	New Pool 1 February 1980
Willesden Green Cardium G	0.0	8.8	+8.8	New Pool 1 July 1980
Willesden Green Second White Specks B	0.0	73.0	+73.0	New Pool 1 September 1980
Windfall D-3B*	513.0	116.0	-397.0	Re-evaluation - Decreased OIP & Ri - Enhanced recovery recognition
Windfall D-3C	79.5	159.0	+79.5	Enhanced recovery recognition
Wintering Hills Viking Q	conf	4.1	-	Lost confidential status 1 April 1980
Wintering Hills Lower Mannville Q	conf	10.5	-	Lost confidential status 1 April 1980
Wintering Hills Lower Mannville R	0.0	51.8	+51.8	New Pool 1 March 1980
Youngstown Upper Mannville A	0.0	4.5	+4.5	New Pool 1 October 1980
Zama Muskeg DD	10.3	12.7	+2.4	Resumed production operations
Zama Keg River JJ	33.0	24.8	-8.2	Pool suspended - Set RiN = Np
Zama Keg River F3F	33.1	63.0	+29.9	Resumed production operations
Zama Keg River Q4Q	19.0	21.5	+2.5	Resumed production operations
Zama Keg River D5D	122.0	7.7	-114.3	Pool suspended - Set RiN = Np

Pool Heavy Crude Oil	Initial Established Crude Oil At 31 Dec. 1979 10^3 m^3	At 31 Dec. 1980 10^3 m^3	Change 10^3 m^3	Reasons for Change
Alderson Upper Mannville R	conf	67.9	+16.8	Lost confidential status 1 March 1980 - Increased OIP
Alderson Upper Mannville S	conf	105.0	+34.5	Lost confidential status 1 July 1980 - Increased OIP
Alderson Upper Mannville T	conf	7.1	-	Lost confidential status 1 April 1980
Alderson Lower Mannville L	conf	23.8	-	Lost confidential status 1 May 1980
Alderson Lower Mannville N	0.0	6.8	+6.8	New Pool 1 August 1980
Amisk Upper Mannville I	2.2	0.8	-1.4	Pool suspended - Set RiN = Np
Bantry Mannville M	22.4	6.5	-15.9	Pool suspended - Set RiN = Np
Barrhead Banff A	0.0	5.9	+5.9	New Pool 1 October 1980
Chauvin South Sparky I	0.1	7.8	+7.7	Resumed production operations
Chauvin South Sparky A & B*	1 530.0	1 550.0	+20.0	Re-evaluation - Enhanced recovery pool
Chauvin South Sparky N & R	41.8	65.0	+23.2	Re-evaluation - Coalesced with Sparky O Pool
Chauvin South Lloydminster F	9.5	6.9	-2.6	Re-evaluation - Increased OIP Decreased Ri
Cherhill Banff E	0.0	6.6	+6.6	New Pool 1 May 1980
Countess Upper Mannville D*	4 960.0	5 050.0	+90.0	Re-evaluation - Enhanced recovery pool
Countess Lower Mannville G	conf	12.6	-	Lost confidential status 1 February 1980
Edgerton Lloydminster B	10.0	0.5	-9.5	Pool suspended - Set RiN = Np
Enchant Lower Mannville F	undef	8.9	-	New Pool 1 August 1980
Gladys Rundle D	0.0	18.3	+18.3	New Pool 1 June 1980
Grand Forks Upper Mannville D	19.0	26.6	+7.6	Re-evaluation - Increased OIP
Grand Forks Lower Mannville E*	507.0	607.0	+100.0	Re-evaluation - Enhanced recovery pool
Grand Forks Lower Mannville J	0.2	30.0	+29.8	Resumed production operations

	Initial Established Crude Oil			
Pool Heavy Crude Oil	At 31 Dec. 1979 10^3 m^3	At 31 Dec. 1980 10^3 m^3	Change 10^3 m^3	Reasons for Change
Grand Forks Lower Mannville L*	25.0	44.0	+19.0	Enhanced recovery recognition
Grand Forks Lower Mannville P	6.5	5.2	-1.3	Pool suspended - Set RiN = Np
Grand Forks Lower Mannville R	undef	58.8	-	Lost confidential status 1 November 1980
Grand Forks Lower Mannville S	undef	84.0	+32.9	New Pool 1 February 1980 - Coalesced with Q Pool
Grand Forks Sawtooth B	23.3	15.8	-7.5	Re-evaluation - Increased OIP, Decreased Ri
Gunn Banff A	undef	15.0	-	New Pool 1 February 1980
Hays Lower Mannville H	conf	4.3	-	Lost confidential status 1 February 1980
Hayter Sparky E	conf	9.4	+5.5	Lost confidential status 1 July 1980
Hayter Sparky F	0.0	4.2	+4.2	New Pool 1 May 1980
Hayter Dina C	5.6	15.1	+9.5	Re-evaluation - Increased OIP
Horsefly Lake	849.0	1 090.0	+241.0	Re-evaluation - Enhanced recovery pool
Jenner Lower Mannville B	9.4	0.3	-9.1	Pool suspended - Set RiN = Np
Killam Colony F	0.0	7.0	+7.0	New Pool 1 November 1980
Lathom Lower Mannville A	14.9	26.6	+11.7	Re-evaluation - Increased OIP
Lindbergh Sparky B	0.0	16.6	+16.6	New Pool 1 March 1980
Lindbergh Sparky C	0.0	8.1	+8.1	New Pool 1 March 1980
Lindbergh Sparky F	0.0	3.6	+3.6	New Pool 1 October 1980
Lindbergh McMurray A	12.8	25.9	+13.1	Re-evaluation - Increased OIP
Lindbergh McMurray B	0.0	29.9	+29.9	New Pool 1 March 1980
Little Bow Upper Mannville O	conf	7.3	-	Lost confidential status 1 June 1980
Little Bow Upper Mannville P	conf	11.5	-	Lost confidential status 1 August 1980
Little Bow Upper Mannville Q	undef	2.5	-	New Pool 1 March 1980

ATTACHMENT II (CONT'D)

Pool Heavy Crude Oil	Initial Established Crude Oil At 31 Dec. 1979 10^3 m^3	 At 31 Dec. 1980 10^3 m^3	Change 10^3 m^3	Reasons for Change
Little Bow Upper Mannville R	0.0	2.3	+2.3	New Pool 1 July 1980
Little Bow Upper Mannville S	undef	53.2	-11.3	New Pool 1 September 1980 - Decreased OIP
Little Bow Lower Mannville L	conf	4.8	-	Lost confidential status 1 June 1980
Little Bow Lower Mannville M	0.0	2.0	+2.0	New Pool 1 May 1980
Little Bow Lower Mannville N	0.0	2.7	+2.7	New Pool 1 June 1980
Lloydminster Colony I	undef	1.6	-	New Pool 1 January 1980
Lloydminster Sparky CC	105.0	152.0	+47.0	Re-evaluation - Coalesced with GG & HH Pools
Lloydminster Sparky RR	conf	6.2	-	Lost confidential status 1 January 1980
Lloydminster Sparky SS	conf	10.1	-	Lost confidential status 1 February 1980
Lloydminster Sparky WW	0.0	1.0	+1.0	New Pool 1 July 1980 - Suspended
Lloydminster Sparky XX	undef	10.8	+4.7	New Pool 1 December 1980 - Increased OIP
Lloydminster General Petroleum N	6.5	0.6	-5.9	Pool suspended - Set RiN = Np
Lloydminster General Petroleum O	2.8	0.1	-2.7	Lost confidential status 1 July 1980 - Abandoned
Lloydminster Cummings C	conf	2.0	-	Lost confidential status 1 January 1980
Medicine Hat Lower Mannville A	3.2	4.7	+1.5	Re-evaluation - Increased OIP
Medicine Hat Lower Mannville B	5.0	7.1	+2.1	Re-evaluation - Increased OIP
Medicine Hat Lower Mannville C	undef	3.2	+1.9	Lost confidential status 1 May 1980
Medicine Hat Lower Mannville D	undef	2.9	+1.5	New Pool 1 August 1980 - Increased Ri
Princess Pekisko B	13.5	16.8	+3.3	Re-evaluation - Increased OIP

ATTACHMENT II (CONT'D)

Pool Heavy Crude Oil	Initial Established Crude Oil At 31 Dec. 1979 10^3 m^3	At 31 Dec. 1980 10^3 m^3	Change 10^3 m^3	Reasons for Change
Provost Upper Mannville U	0.0	2.0	+2.0	New Pool 1 November 1980
Provost Upper Mannville V	0.0	3.8	+3.8	New Pool 1 December 1980
Retlaw Mannville V	6.7	22.6	+15.9	Re-evaluation - Increased OIP
Retlaw Mannville W	11.0	35.6	+24.6	Re-evaluation - Increased OIP
Retlaw Mannville MM	0.0	0.2	+0.2	New Pool 1 March 1980
Retlaw Mannville PP	0.0	45.6	+45.6	New Pool 1 August 1980
Rivercourse Sparky C	5.5	13.2	+7.7	Re-evaluation - Increased OIP
Suffield Upper Mannville Q	0.0	0.1	+0.1	New Pool 1 February 1980 Abandoned
Suffield Lower Mannville J	2.4	1.2	-1.2	Pool abandoned - Set RiN = Np
Swimming Upper Mannville A	undef	2.8	-2.2	New Pool 1 July 1980
Taber Mannville D	2 290.0	2 260.0	-30.0	Re-evaluation - Enhanced recovery pool
Taber Mannville I	undef	1.5	-	New Pool 1 January 1980
Taber North Taber G	52.0	63.5	+11.5	Re-evaluation - Increased OIP
Taber South Mannville A*	1 368.0	1 380.0	+12.0	Re-evaluation - Enhanced recovery pool
Taber South Mannville E	conf	5.1	-	Lost confidential status 1 January 1980
Taber South Mannville F	0.0	22.3	+22.3	New Pool 1 September 1980
Turin Lower Mannville T	conf	11.2	-	Lost confidential status 1 July 1980
Viking-Kinsella Upper Mannville R	38.3	1.3	-37.0	Pool suspended - Set RiN = Np
Viking-Kinsella Upper Mannville CC	0.0	3.8	+3.8	New Pool 1 July 1980
Viking-Kinsella Wainwright B*	4 550.0	4 560.0	+10.0	Re-evaluation - Enhanced recovery pool

Pool Heavy Crude Oil	Initial Established Crude Oil At 31 Dec. 1979 10^3 m^3	At 31 Dec. 1980 10^3 m^3	Change 10^3 m^3	Reasons for Change
Viking-Kinsella Wainwright H	2.9	6.8	+3.9	Re-evaluation - Increased OIP
Viking-Kinsella Wainwright I	0.0	3.8	+3.8	New Pool 1 July 1980
Wainwright Colony W	0.0	6.6	+6.6	Previously a gas pool
Wainwright Sparky G	conf	2.5	-	Lost confidential status 1 January 1980
Wainwright Sparky I	0.0	3.1	+3.1	New Pool 1 November 1980
Wainwright Wainwright & Sparky A	9 010.0	9 000.0	-10.0	Re-evaluation - Enhanced recovery pool
Wildmere Sparky G	0.0	1.5	+1.5	New Pool 1 April 1980
Wildmere General Petroleum A	8.7	5.0	-3.7	Re-evaluation - Previously Sparky F pool
Wrentham Lower Mannville A	0.3	19.3	+19.0	Resumed production operations

ATTACHMENT III

SCHEMES WHICH RECEIVED ENHANCED RECOVERY RECOGNITION IN 1980

Pools Light and Medium Crude Oil	Depletion Mechanism	Scheme Recovery Factor Modifier
Bigoray Nisku D Approval No. 2828	Waterflood	1.250
Bigoray Nisku G Approval No. 3022	Waterflood	1.500
Bigoray Nisku I Approval No. 2996	Waterflood	1.230
Boundary Lake South Triassic H Approval No. 2813	Waterflood	2.800
Cym Pem Nisku A Approval No. 3092	Waterflood	2.250
Ferrier Cardium D Approval No. 2360	Waterflood	2.500
Ferrier Cardium G Approval No. 2960	Waterflood	5.000
Ferrier Cardium G Approval No. 2961	Waterflood	5.000
Ferrier Cardium G Approval No. 2962	Waterflood	5.000
Ferrier Cardium G Approval No. 3056	Waterflood	5.000
Fox Creek BHL A Approval No. 2860	Waterflood	2.500
Highvale Lower Mannville A Approval No. 2920	Waterflood	3.125
Medicine River Glauconitic A Approval No. 2518	Waterflood	2.000
Medicine River Glauconitic A Approval No. 3139	Waterflood	2.000
Parflesh Lower Mannville C Approval No. 2549	Waterflood	1.955

ATTACHMENT III (CONT'D)

Pools Light and Medium Crude Oil	Depletion Mechanism	Scheme Recovery Factor Modifier
Pembina Key Belly River U Approval No. 2569	Waterflood	2.308
Pembina Nisku C Approval No. 2864	Waterflood	1.670
Pembina Nisku J Approval No. 2988	Waterflood	1.340
Sunset Triassic A Approval No. 2704	Waterflood	2.700
Windfall D-3B Approval No. 3031	Gasflood	1.200
Windfall D-3C Approval No. 2924	Gasflood	2.000
Heavy Crude		
Grand Forks Lower Mannville L Approval No. 3047	Waterflood	1.330
Horsefly Lake Mannville Approval No. 2774	Waterflood	2.000

ATTACHMENT IV

PRE-BOOKED RESERVE INCREMENTS FOR SCHEMES APPROVED IN 1980 AND AWAITING ENHANCED RECOVERY RECOGNITION

Pools Light and Medium Crude Oil	Primary (Set) 10^3m^3	Enhanced 10^3m^3	Depletion Mechanism
Bigoray Nisku B Approval No. 3077	450.0	900.0	Solventflood
Brazeau River Nisku A Approval No. 3062	2120.0	3980.0	Solventflood
Brazeau River Nisku B Approval No. 3028	920.0	1200.0	Waterflood
Brazeau River Nisku E Approval No. 3174	900.0	1300.0	Solventflood
Pembina Belly River FFF and GGG Approval No. 3188	90.0	194.0	Waterflood
Pembina Ellerslie A Approval No. 3111	120.0	198.0	Waterflood
Pembina Nisku A Approval No. 3029	1120.0	1430.0	Waterflood
Pembina Nisku G A-proval No. 3126	1200.0	2100.0	Solventflood
Pembina Nisku K Approval No. 3140	972.0	1700.0	Solventflood
Pembina Nisku L Approval No. 3167	1680.0	1930.0	Waterflood
Pembina Nisku M Approval No. 3146	1140.0	1570.0	Gasflood
Stettler South D-2 Approval No. 3072	288.0	410.0	Waterflood
Westpem Nisku C Approval No. 3159	1600.0	2040.0	Waterflood
Heavy Crude			
Countess Upper Mannville D Approval No. 3075	134.0	590.0	Waterflood
Taber Mannville D Approval No. 3081	115.0	265.0	Waterflood
Wrentham Lower Mannville C Approval No. 3184	53.8	113.0	Waterflood

CX
MAR 23 1981

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

Information Letter 81-6

TO: All Oil and Gas Well Operators
and Pipeline Companies

ACCESS ROADS IN IMPROVEMENT DISTRICTS

Alberta Transportation has asked the Board to remind companies constructing access roads onto local roads in Imporvement Disricts that prior permission is required from the District Transportation Engineer.

A list of District offices and areas of jurisdiction is attached.

ISSUED in Calgary, Alberta 5 March 1981.

VE Bohme

V. E. Bohme
Board Member

DISTRICT TRANSPORTATION ENGINEERS

Mr. A. Waller
District Transportation Engineer - Medicine Hat
Provincial Administration Building
770 - 6th Street, SW
Medicine Hat, Alberta T1A 4J6
(Direct Line 184-3640)
(Long Distance 529-3460)

County of Newell #4
County of Forty Mile #8
Improvement District #1

Mr. L.J. Hempsey
District Transportation Engineer - Lethbridge
Administration Building
9th Street & 3rd Avenue, North
Lethbridge, Alberta
T1H 1E9
(Direct Line 181-5480)
(Long Distance 329-5480)

County of Warner #5
County of Vulcan #2
County of Lethbridge #26
Improvement District #4
Improvement District #6
Improvement District #5
M.D. of Cardston #6
M.D. of Taber #14
M.D. of Willow Creek #26
M.D. of Pincher Creek #9

Mr. Ray McFetridge
District Transportation Engineer - Calgary
Rm. 107, Hill Park
2411 - 4th Street, NW
Calgary, Alberta
T2M 2Z8
(Direct Line 161-6311)
(Long Distance 261-6311)

County of Wheatland #16
County of Mountain View #17
M.D. of Foothills #31
M.D. of Rocky View #44
Improvement District #8

Mr. Monty McGregor
District Transportation Engineer - Hanna
Box 1300
Hanna, Alberta
T0H 1T0
(Long Distance 854-4451)

M.D. of Acadia #34
M.D. of Starland #47
M.D. of Kneehill #48
Special Area 2
Special Area 3

Mr. F.A. Derkat
District Transportation Engineer - Red Deer
Box 5002
Red Deer, Alberta
T4N 5Y5
(Direct Line 151-5200)
(Long Distance 343-5200)

County of Ponoka #3
County of Lacombe #14
County of Wetaskiwin #10
County of Red Deer #23
Improvement District #10
Improvement District #11

Mr. Keith Helberg
District Transportation Engineer - Stettler
Postal Bag 600
Stettler, Alberta
T0C 2L0
(Long Distance 742-4481)
(Direct Line 153-1101)

County of Stettler #6
County of Paintearth #18
County of Camrose #22
County of Flagstaff #29
M.D. of Provost #52
Special Area #4

Mr. Lloyd Werboweski
District Transportation Engineer - Vermilion
Box 690
Vermilion, Alberta
T0B 4M0
(Direct Line 141-1251)
(Long Distance 853-2811
Ext. 251, 252,253)

County of Beaver #9
County of Lamont #30
County of Minburn #27
County of Two Hills #21
County of Vermilion River #24
M.D. of Wainwright #61
Improvement District #13

Mr. Henri Hetu
District Transportation Engineer - Lac La Biche
Box 1529
Lac La Biche, Alberta
T0A 2C0
(Long Distance 623-4474)

County of Smoky Lake #13
County of St. Paul #19
M.D. of Bonnyville #87
Improvement District #18
Improvement District #24

Mr. Bill Wells
District Transportation Engineer - Edmonton
902 College Plaza
8215 - 112 Street
Edmonton, Alberta
T6G 1K6
(Direct Line 427-3147)

County of Leduc #25
County of Strathcona #20
County of Parkland #31
County of Lac Ste. Anne #28
M.D. of Sturgeon #90

Mr. R.A. Oberg
District Transportation Engineer - Edson
Box 1748
Edson, Alberta
T0E 0P0
(Long Distance 723-3343, Ext. 37, 38, 15)
(Direct Line 130-1165)

Improvement District #14
*Part of I.D. #15 (includes
Twp. 56-10-5
Twp. 56-11-5
Twp. 56-12-5
Twp. 57 Ranges 10, 11, 12, 13W of 5
Twp. 58 Ranges 10, 11, 12, 13, 14,
15, 16, 17W of 5
Twp. 59 Ranges 9 to 18W of 5th
60 Ranges 13 to 17W of 5th)
*Part of Improvement District 16 (include
Twp. 54 Ranges 12-W6 to B.C. Border
Twp. 55-10-6 to B.C. Border
56-2-6 to B.C. Border
57-1-6 to B.C. Border)

Mr. Bob Comchi
District Transportation Engineer - Athabasca
Box 1078
Athabasca, Alberta
T0G 0B0
(Long Distance 675-2636)

County of Barrhead #11
County of Thorhild #17
County of Athabasca #12
*Improvement District #17 (includes
Twp. 65, Ranges 25, 26, 27-4
Twp. 65, Ranges 1, 2 - W5
Twp. 66, Ranges 25, 26, 27 - 4
Twp. 66, Ranges 1, 2 - W5
Twp. 67 - 25, 26, 27 - W4th
Twp. 67 - 1, 2 - W of 6th
Twp. 68 - 25, 26, 27 - W4
Twp. 69 Ranges 23, 24, 25, 26, 27 - W
Twp. 69 - 1 - 5

Municipalities Shown as * are divided between more than one District

Cont'd from Page 2	*Improvement District 17 (Cont'd) Twp. 70, Ranges 19 to 27 - W4th Twp 70-1-5 Twp 71 - Ranges 19 to 26 - W4th Twp 71 - 1 & 2 - W5th Twp 72 - Ranges 19 to 26 - W4th Twp 72 - 1 & 2 - W5th Twp 73 - Ranges 18 to 26 - W4th Twp 73 - 1 & 2 - W5th Twp 74 - Ranges 22 to 25 - W4th Twp 74-1-5 Twp 75 - Ranges 22 to 26 - W4th Twp 75-1-5th Twp 64 - Ranges 18 to 13 - 4th Twp 65 - Ranges 18 to 13 - 4th Twp 67 - Ranges 18 to 13 - 4th Twp 67 - Ranges 18 to 13 - 4th
Mr. Bill Beattie District Transportation Engineer - Grande Prairie 8424 - 108 Street Grande Prairie, Alberta T8V 4C7 (Direct Line 121-2310) (Long Distance 539-2310)	County of Grande Prairie #1 M.D. of Spirit River #133 *Improvement District #16 (includes remainder of I.D. not shown in R.A. Oberg's District) Improvement District #19 Improvement District #20
Mr. Clarence Dewald District Transportation Engineer - High Prairie Box 550 High Prairie, Alberta T0G 1E0 (Long Distance 523-3303)	M.D. of Smoky River #130 *Improvement District #17 (includes remainder of I.D. not shown in Bob Comchi's District)
Mr. C. Farr District Transportation Engineer - Peace River Rm. 204, Provincial Bldg. Peace River, Alberta T0H 2X0 (Direct Line 120-6130) (Long Distance 624-6130 Ext. 31, 32)	M.D. of Peace #135 M.D. of Fairview #136 Improvement District #21 Improvement District #22
Mr. T. Mammen District Transportation Engineer - High Level Box 1045 High Level, Alberta T0H 1Z0 (Long Distance 926-3292)	Improvement District #23

APR 7 1981

ENERGY RESOURCES CONSERVATION BOARD
Calgary, Alberta

INFORMATIONAL LETTER
IL 81-7

TO: All Operators and Potential Operators
of Sour Gas Wells in the Okotoks Field and Area

Regional and Municipal Planning Authorities in
the General Okotoks Region

Developers of and Surface Land Owners in the
General Okotoks Region

Purchasers of Major Volumes of Alberta Gas

EXPLORATION FOR AND PRODUCTION OF SOUR GAS IN THE CALGARY-OKOTOKS REGION

This Informational Letter outlines the Board's views respecting planning in the drilling and production of sour gas in the Calgary-Okotoks region as outlined in Figure 1 attached. It also itemizes certain special requirements respecting future applications to the Board for facilities in the area.

The Board notes that recent drilling suggests that the sour gas reserves in the area are likely more extensive than had been visualized a few years ago. This raises a concern that development of potential sour gas reserves in this region may be seriously affected by expansion of the City of Calgary, the Town of Okotoks and increasing subdivision development in the Calgary-Okotoks area. At the same time, there is concern that improperly planned sour gas developments may have significant adverse effects on urban and rural developments.

Over the last several years the Board has held a number of hearings of applications for approval of wells and pipelines in the Okotoks area. As a result of these hearings and other information that the Board received, it requested, in Informational Letter 80-4, that oil and gas developers prepare an overall development plan for the sour gas resources in the region. The plan filed by the industry as a result of that request along with certain information gathered by the Board may be useful to gas producers, municipal governments, and others in planning compatible developments. The industry plan and the other information can be reviewed at the Board's Calgary office upon request and members of the Board staff are available for consultation respecting it.

On reviewing the available information, the Board has come to the following conclusions regarding development in this area:

1. Exploration for and production of gas should be carried out in an expeditious manner, but having regard for existing residential development and in such a way as to allow depletion prior to further significant encroachment from urban growth that will occur over the long-term.

2. In order to expedite depletion of the gas reserves in the area, additional gas processing capacity will likely be required. However, due to the proximity of the existing gas processing plant to the Town of Okotoks, it does not appear reasonable to further expand the plant. Consequently, the Board expects a new processing plant might be proposed for the area.

3. The gas industry should co-ordinate development plans to the maximum extent, including unitization or other business agreements as appropriate, so as to avoid unnecessary or prolonged interference with other activities in the area.

4. Regional and municipal planning authorities, developers, owners of surface land and industry, should cooperate in the expediting of the depletion of the sour gas reserves in order that the producing life of the region may be shortened and so that long-term surface developments will not be unnecessarily impacted by sour gas facilities.

Unless these and other like measures are followed, the Board believes that there could be unavoidable restrictions on land subdivision in the region for an indefinite period of time and also that recovery of significant natural gas resources may be seriously hindered.

The Board intends to continue the processing of well licence, pipeline and other sour gas facility applications for the Okotoks area in the normal manner and will give public notice where appropriate. The unique circumstances in the area caused the Board to require, in addition to its existing stringent requirements, the following special conditions respecting applications within the area specified on Figure 1.

1. All well licence applications must include an indication of the location of the related new pipelines.

2. All facility applications must include:

    (a) Evidence that the proposed developments are in keeping with the objective of rapid efficient depletion of the reservoir.

(b) Evidence that other resource owners in the immediate area have been contacted and that the planned facilities would be used in an optimum manner.

(c) Details of a well thought out and coordinated emergency plan in the unlikely event of an uncontrolled release of sour gas.

For further information respecting the matters referred to in this letter, please contact Mr. E. R. Brushett, Manager of the Board's Environment Protection Department.

ISSUED at Calgary, Alberta on 10 March 1981

ENERGY RESOURCES CONSERVATION BOARD

G J DeSorcy

G. J. DeSorcy
Vice Chairman

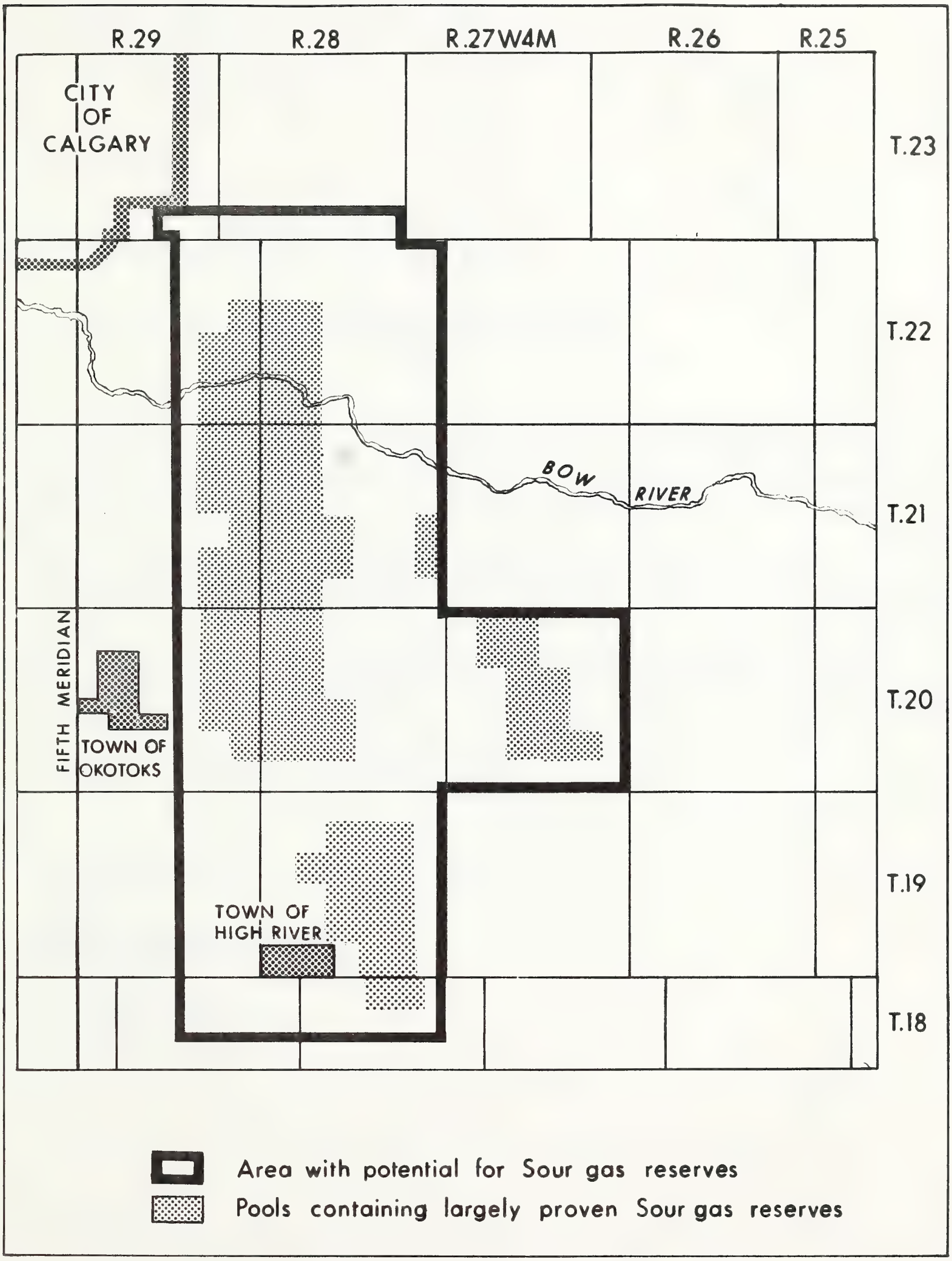

FIGURE 1 CALGARY - OKOTOKS AREA

ENERGY RESOURCES CONSERVATION BOARD
ALBERTA, CANADA

MAY 07 198

ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

Informational Letter
IL 81-8

TO: All Oil and Gas, Pipeline, Coal,
and Hydro and Electric Operators

INTERIM DIRECTIVES AND INFORMATIONAL LETTERS

The Board has reviewed all Interim Directives and Informational Letters concerning energy matters, issued prior to 31 December 1981, and have attached hereto a list of those Interim Directives and Informational Letters that are still applicable.

All Interim Directives and Informational Letters which are not listed on the attachment are no longer applicable or have been superseded, as of 31 December 1981.

All Information Letters and Interim Directives are under review at this time. Some of these will likely be incorporated into the regulations.

ISSUED at Calgary, Alberta on 23 April 1981.

ENERGY RESOURCES CONSERVATION BOARD

GJ DeSorcy

G.J. DeSorcy
Vice Chairman

Attachment

CURRENT STANDING OF ALL INTERIM DIRECTIVES, ISSUED BY THE BOARD, STILL EFFECTIVE AS OF 31 DECEMBER 1980

GENERAL

ID	70-4	Post-Hearing Meetings
ID	71-3	Zama Lake Area
ID-G	77-1	Preservation of Archaeological, Paleontological and Historical Resources

OIL & GAS

ID-OG	73-3	Oil Sands Data
ID-OG-PL	75-1	Spill Contingency Planning
ID-OG	75-2	Sump Fluid Disposal Requirements
ID-OG	76-1	Minimum Casing and Cementing Requirements - Shallow Gas Well Development
ID-OG	76-2	Emergency Procedure Plans for Sour Gas Facilities
ID-OG	76-3	Servicing Operations on Shallow Gas Wells
ID-OG	77-1	Applications Under The Oil and Gas Conservation Act for Industrial Development Permits
ID-OG	77-2	Special Drilling Spacing Units for Pre-1968 Off-target Oil or Gas Wells
ID-OG-PL	78-2	Licensing of Flow Lines

HYDRO & ELECTRIC

ID-HEE	72-1	Re: Regulations Concerning Records and Statistics to be Submitted to the Board
ID-HEE	71-2	Interim Procedures and Requirements

PIPELINES

ID-PL	76-1	Polyethylene Pipelines within Highway or Road Right of Ways

INTERIM DIRECTIVE ISSUED IN 1979

ID	79-2	Minimum Distance Requirements Separating New Sour Gas Facilities from Residential and Other Developments

INTERIM DIRECTIVES ISSUED IN 1980

ID	80-1	Cancel
	80-2	Noise Control Guidelines
	80-3	Amendment to Interim Directive ID-OG-PL 78-2 Licensing of Flow Lines

CURRENT STANDING OF ALL INFORMATIONAL LETTERS, ISSUED BY THE BOARD, STILL EFFECTIVE AS OF 31 DECEMBER 1980

OIL & GAS

IL	70-14	Salvage of Production Casing in Oil Pools
	70-15	Oil for Plant Fuel
	70-16	Oil Pools Underlying Provincial Boundaries
	70-31	Provincial Program of Gas Gravity Surveys for Crude Oil Pools for the Purpose of Providing Tables for Determining Gas Gravity for Orifice Metering
IL	71-10	Sampling of Oil Reservoir Fluids
	71-15	Placing of Crude Oil Pools on Good Production Practice
	71-20	Submission of Monthly Reports and New Well Reports
	71-23	Pressure Surveys and Back Pressure Tests in Gas Pools
	71-32	Annual Accounting Periods (AAP) Crude Oil Wells and Pools
IL-OG	72-7	Conductor Pipe - Milk River Wells
	72-11	Well Spacing and Infill Wells in Oil Pools
	72-20	Environmental Management and Pollution Control - Gas Processing Operations
IL-OG	73-2	Operators in the Provost Field
	73-9	Maximum Daily Rates of Production for Gas Wells
	73-12	Allowable Penalties Pools Having a Single Well, Block or Project and Confidential Pool
	73-14	Replacement of Withdrawals - Oil Recovery Enhancement Schemes
	73-21	Athabasca Oil Sands Deposit
	73-26	Gas Processing Plant Turnarounds
	73-33	Use of Chemical Oil Spill Treating Agents for Oil Spill Clean Up
IL-OG	74-4	Incentive Exploratory Wells Under Exploratory Drilling Incentive Regulations, 1974
	74-5	Sulphur Recovery and Sulphur Dioxide Emissions at Gas Processing Plants
	74-8	Well Licence Applications and Procedures
	74-9	Water-Oil Ration Penalty Relief Amber, Larne, Virgo and Zama Fields
	74-10	Off-Target Wells in Pools Subject to Good Production Practice
	74-11	Information Required in Applications to Amend Board Order SU 800 Concerning Target Areas for Wells in South Eastern Alberta

IL-OG	75-2	Well Licence Deposits
	75-5	Measurement and Reporting of Gas Produced with Oil
	75-7	Incentive Exploratory Wells Under the Exploratory Drilling Incentive Regulations, 1974
IL-OG-PL	75-8	Spill Training Exercises
	75-9	Gas Well Testing - Milk River Formation, Medicine Hat Zone, and Second White Specks Zone
	75-11	Incentive Exploratory Wells: Amendments to the Definitions "1½ Mile Area" and "3 Mile Area" in Informational Letter No. IL-OG 74-4
	75-13	Measurement and Accounting of Production of Milk River, Medicine Hat and Second White Specks Gas Wells in the Fields and Areas Outlined in Appendix I
	75-14	Spacing Unit Consideration when Applying for Well Licences
	75-19	Proration Plan - Maximum Rate Limitation and Allowable Surveillance System
IL-OG	76-7	Administration of Concurrent Production and Production Allowable - Provost Viking A Pool, Provost Viking K Pool and Provost Viking C Pool
IL-OG-PL	76-8	Site Preparation Near Rural Gas Cooperative Distribution Systems
IL-OG	76-9	Surveillance of the Effect of Production Rate on Recovery and the Application of Maximum Rate Limitations
	76-12	Good Production Practice
	76-14	Drilling Cuttings and Core
IL-OG	76-16	Surveillance of the Effect of Production Rate on Recovery and the Application of Maximum Rate Limitations
	76-17	Incinerator Stack Surveys
	76-20	The Production of Gas in Oil Sands Areas
	76-21	Naming of Wells to be Considered On-Target Under Special Drilling Spacing Units
	76-23	Policy on Establishing Crude Oil Reserve Estimates Recovery Factor Modifiers, and Maximum Rate Limitations
	76-24	Stack Exit Temperatures for Acid Gas Incinerators Associated with Gas Processing Plants
IL-OG	77-4	Applications - Subsurface Water Disposal Schemes
	77-6	Solvent Flood Potential
	77-9	Gas Well Off-Target Penalty Factors
IL-OG	78-12	Policy on Experimental Schemes - Conventional Oil Pools or Oil Sands
	78-17	Guidelines for Plume Dispersion Calculations
	78-21	Flexible Hose - Bleed-Off and Kill Line Applications

PIPELINES

IL-OG-PL	75-8	Spill Training Exercises
IL-PL	76-1	Leak Prevention and Detection
	76-6	Pipeline Computer File
	76-7	3306 Polyethylene Gas Pipe Produced from N5303 Resin
	76-8	Low Temperature Installation of Polyethylene Plastic Pipe
IL-OG-PL	76-8	Site Preparation Near Rural Gas Cooperative Distribution Systems
	76-15	Construction Approvals for Natural Gas Compressor Stations
IL-PL	78-2	Gas Protection Branch and Energy Resources Conservation Board Responsibilities for Permitting and Licensing of Rural Gas Service Lines
	78-3	PE 3306 Pipe Replacement

HYDRO & ELECTRIC

IL-HEE	72-1	Air Pollution Monitoring Program
IL-HEE	73-1	Thermal Power Plant Stack Surveys
IL-HEE	74-1	Environmental Management and Pollution Control Thermal Power Plants
IL-HEE-PL	78-1	Alternative Routes - Electric Transmission Line and Pipeline Applications

COAL

IL-C	75-1	To: All Mine and Quarry Operators (Safety)
	75-4	Personnel Safety Measures Around Draglines, Shovels, and Bucket Wheels
IL-C	76-9	Braking Performance Standards for Off-Highway Vehicles

GENERAL

IL	73-1	Board Decisions
IL	76-1	All Prospective Applicants for Major Energy Resource Projects

INFORMATIONAL LETTERS ISSUED IN 1979

IL	79-1	Incentive Exploratory Wells - Preliminary Appraisals Before Licensing
	79-2	The Production of Gas in Oil Sands Areas
	79-3	Applications Under The Clean Water Act for the Renewal of Operating Licenses
	79-8	Plans Submitted with Well Licence Applications
	79-9	Revisions of the "Gas Processing Plants Waste Water Management Standards - September 1973" Issued by the Department of the Environment
	79-11	Low Temperature Installation of Polyethylene Plastic Pipe
	79-12	Gas Processing Plant Analyses
	79-13	Administration Respecting Common Gas Purchaser Applications and Orders
	79-16	Revised Incinerator Stack Exit Temperature Criteria for Plants Processing Sour Gas
	79-17	Indirect Fired Heater Coils for Pipeline Service
	79-18	Preservation of Archaeological, Paleontological and Historical Resources
	79-19	Review of Base GORS for Pools Defined Prior to 1 January 1979
	79-21	Commingling of Gas Production Elmworth Area
	79-22	Revised Environmental Monitoring Requirements for Plants Processing Sour Gas
	79-24	Pembina Nisku Basin Commencement of Enhanced Recovery Schemes
	79-25	Applications Under The Gas Resources Preservation Act for the Removal of Gas from Alberta

INFORMATIONAL LETTERS ISSUED IN 1980

IL	80-1	Development of Deep-Basin Multi-Zone Gas Production
	80-2	Sampling of Reservoir Fluids
	80-4	Overall Development Plan Okotoks Area
	80-5	Cementing of Coal Exploration Drillholes
	80-7	Permitting and Licensing of Flow Lines
	80-9	Annual Reservoir Review for Gas Pools Gas Reservoir Review 80-1
	80-10	Procedures and Economic Criteria for the Assessement of Future Alberta Gas Trunk Line Applications
	80-11	Joint Use of Right of Way
	80-12	Gas Well Testing Pressure Measurement Forms in SI
	80-13	Incentive Exploratory Wells Drilled Under the Exploratory Drilling Incentive Regulation, 1978
	80-14	Coal Mining and Well-Drilling on the same Land - New Policy

IL	80-15	Gas Well Testing Milk River Formation, Medicine Hat Zone, and Second White Specks Zone
	80-16	Tertiary Enhanced Recovery Potential
	80-17	Cancel
	80-18	ERCB Mailing List Policy
	80-19	Environmental Impact Assessments
	80-20	Publication of Sulphur Values
	80-22	Industrial and Manufacturing Operations Statement
	80-23	Experimental Schemes - Release of Applications and Basic Well and Geological Records - Confidentiality Provision for Unique Design Data and Progress Reports on Operating Results - Requests for Information of Local Interest
	80-24	Sulphur Recovery Guidelines Gas Processing Operations
	80-25	New Bottomhole Pressure Recorders
	80-26	Medicine Hat New Address
	80-27	Licence and Permit Fees
	80-28	Gas Reservoir Review 81-1
	80-29	Application Submission Deadline
	80-30	Application for Approval of Natural Gas Compressors